ATTACHMENT 5
LICENSE AMENDMENT REQUEST
EXTENDED POWER UPRATES

LICENSING REPORT

FLORIDA POWER & LIGHT
ST. LUCIE NUCLEAR PLANT, UNIT 1

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1.0 INTRODUCTION TO THE ST. LUCIE PLANT UNIT 1 EXTENDED POWER UPRATE LICENSING REPORT

General Overview of the St. Lucie Unit 1 Extended Power Uprate Licensing Report

Florida Power and Light (FPL) is proposing an extended power uprate (EPU) that would increase the St. Lucie Unit 1 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:

$(2700 \text{ MWt} \times 1.10) \times 1.017 \cong 3020 \text{ MWt}$
$[(3020 \text{ MWt} - 2700 \text{ MWt})/2700 \text{ MWt}] \times 100 \cong 11.85\%$.

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 (CLB), 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, when doing so would facilitate understanding the effects of the EPU on St. Lucie Unit 1. 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.

LR Table 1.0-1 provides a list of the key plant changes required to support operation at the uprate power level. LR Table 1.0-2 provides a list of key changes to the CLB 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.

LR Table 1.0-3 provides a list of new and re-sequenced key emergency operating procedure (EOP) operator actions credited in the accident analyses. LR 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, but which are not dependant on NRC approval of the LAR, are planned to be implemented no later than the Fall 2011 refueling outage. Power ascension to the EPU power level is planned to commence following NRC approval of the EPU LAR and the completion of the Fall 2011 refueling outage. The following discussion summarizes the key physical plant changes.

Reactor System

Reactor Core and Fuel Design

The uprate fuel will utilize the MONOBLOCTM guide tube design. As part of the EPU changes, the allowed enrichment of new fuel will increase to a maximum planar average of 4.6 weight percent (w/o) U-235. The core operating limits will continue to be established using NRC-approved methodologies, and fuel design requirements will continue to be satisfied. 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, the 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 606°F, based on the 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.

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 (SG) low-level narrow range trip setpoint will be changed from ≥ 20.5% to ≥ 35%. Refer to LR Section 2.13, Risk Evaluation, for details.

Accident Mitigation Systems

Several modifications will be completed prior to implementation of the EPU. The safety injection tanks (SITs) design pressure will be increased to 280 psig. Consistent with the proposed Technical Specifications (TS) change, the minimum boron concentration in the SITs, boric acid makeup tanks, and refueling water tank will be increased. Modifications will be implemented to increase hot leg injection flow rate during simultaneous hot and cold leg injection to maintain the ability to preclude boron precipitation. Control room operated containment purge system valves will be added to allow online containment venting as a means to limit the maximum initial containment positive pressure.

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.

Fuel Storage

Spent Fuel Storage

To enhance criticality control in the spent fuel storage pool, a new neutron absorption material (METAMIC^{TM} rack inserts) will be added to selected storage cells. Refer to LR Section 2.8.6.2, Spent Fuel Storage, for details.

Steam and Power Conversion System

Steam Generator

The SG steam outlet pressure for the uprate will be approximately 856 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. 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. Due to higher main steam flows at uprate conditions, the main steam isolation valves (MSIVs) will be modified to improve their structural integrity and fatigue life. The main steam system design pressure and temperature of 985 psig (1000 psia) and 550°F bound the maximum EPU operating conditions. MSSV operability setpoints will remain unchanged for EPU. The as-found tolerances on the MSSVs listed in TS Table 3.7-1 will be changed for operational flexibility to ± 3% for the eight MSSVs at the 1000 psia setpoint, and +2%/-3% for the eight MSSVs at the 1040 psia 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 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 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 will be increased and valve response time decreased to maintain operating margin under EPU conditions, and to decrease challenges to the reactor protection system by increasing the size of the step load reduction that can be mitigated by the control systems without a reactor trip. 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. St. Lucie Unit 1 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 Section 2.5.1.1.3, Circulating Water System, and LR Section 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). 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. The condensate and feedwater 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.

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 Section 2.4.4, Measurement Uncertainty Recapture Power Uprate.

Heater Drains

Heater drain pumps will be replaced to 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 provides the safety-related water source for the AFW system. Due to the increase in the uprate decay heat load, a revision to TS 3/4.7.1.3, Condensate Storage Tank, is required to increase the minimum contained water volume. Refer to LR Section 2.5.4.5, Auxiliary Feedwater, 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 replacement of the generator 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 and increasing short circuit capability as required. The two three-phase main transformer oil pumps and coolers will be upgraded to achieve the design rating of 635 MVA for each transformer (1270 MVA total) 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 LR 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 LR 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 1 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.

Plant Programs

Environmental Qualification of Electrical Equipment

As a result of EPU, localized areas in the reactor auxiliary building (RAB) have changed from a mild environment to a harsh environment. This change results in several components in the RAB HVAC area requiring installation of radiation shielding prior to EPU implementation. Refer to LR Section 2.3.1, Environmental Qualification of Electrical Equipment, for details.

Current Licensing Basis

The CLB is presented in the Updated Final Safety Analysis Report (UFSAR) and other docketed material. The CLB includes the application of various general design criteria (GDC) originally developed by industry (Atomic Industrial Forum (AIF)) in the early 1960s to provide consistent guidance to evaluate the design and performance of commercial nuclear power plants which were an emerging industry. The fundamental precept in the development of these GDC was to identify plant performance criteria which, if satisfied by specific design of structures, systems, and components (SSCs), would provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public with respect to the radiological consequences of normal plant operation and unlikely postulated accidents. The GDC are intended to provide general objectives against which the facility design may be judged. Absent significant commercial nuclear plant operating experience at the time, the safety philosophy at this early stage of industry development was to incorporate appropriate engineered safeguards with conservative safety margins into plant design and into the analyses of the probability and consequences of postulated accidents.

As the commercial nuclear power industry began to mature, both the industry and the regulatory agency gained the benefit of increased, although still limited, operating experience and advances in technology. This resulted, over time, in an increase in regulatory guidance and requirements for plant design and operation.

In 1971, the Atomic Energy Commission (AEC) issued 10 CFR 50, Appendix A, General Design Criteria (36FR03255, 2/20/71). These proposed GDC had been published for interim use in 1967. The GDC are intended to establish minimum requirements for the principal design standards. The Appendix A GDC were in many instances similar to the former AIF GDC, but they were expanded to include additional design considerations (both AIF and NRC GDC are discussed in the UFSAR). St. Lucie Unit 1 historical documents indicate that the AEC GDC issued for interim use in July 1967 were applied to the St. Lucie Unit 1 design prior to issuance of the Operating License in 1976. Details concerning design relative to the GDC are found in UFSAR Section 3.1, which addresses conformance to both the AIF GDC (UFSAR Section 3.1.1) and the NRC GDC (Section 3.1.2).

Through the 1970s and into the 1980s there were a significant number of new regulatory requirements and guidance documents issued. By the late 1970s, the documented scope of review for plant licensing had expanded substantially from the era when St. Lucie Unit 1, and several other older operating plants, were licensed. Federal regulations were expanded; Safety Guides (later renamed Regulatory Guides), Branch Technical Positions and Standard Review Plans (NUREG-75/087 dated 12/75) were developed; and, various NRC generic communications were being continuously issued.

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 CLB as a result of the EPU are listed in LR 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 1 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 March 1, 2016 to March 1, 2036, 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 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 Plant Unit 1 Extended Power Uprate Licensing Report
1.1	Nuclear Steam Supply System Parameters
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	Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding
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	Caldon Ultrasonics Engineering Reports
Appendix G	RCS Pressure and Temperature Limits and Low-Temperature Overpressure Protection Report For 54 Effective Full Power Years
Appendix H	Grid Stability Analysis and System Impact Study for St. Lucie Plant with Proposed EPU
Appendix I	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 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

The 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
Accident Mitigation Systems			
Increase safety injection tank design pressure	X		2.8.5.0
Increase reactor hot leg safety injection flow	X		2.8.5.6.3
Add online containment purge capability	X		2.6.1
Spent Fuel Storage			
Add METAMIC™ inserts to spent fuel pool storage racks	X		2.8.6.2
Steam and Power Conversion System			
Replace moisture separator reheaters and upgrade level controls	X		2.5.5.1
Upgrade main steam isolation valves	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 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
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

Table 1.0-1
Extended Power Uprate – Physical Plant Changes

Description	Support EPU	Improve Operating Margin	LR Section
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 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
Upgrade main transformer cooling systems	X		2.3.3
Upgrade iso-phase bus duct cooling system	X		2.3.3
Modify switchyard components	X	X	2.3.2
Environmental Qualification			
EQ radiation shielding changes for electrical equipment	X		2.3.1

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, including the transition to the realistic large break LOCA (RLBLOCA) methodology.	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 S-RELAP5 code was used to perform the station blackout analysis described in LR Section 2.3.5, Station Blackout, as well as the loss of normal feedwater transient discussed in LR Section 2.5.4.5, Auxiliary Feedwater.	2.3.5 2.5.4.5
For the station blackout event, reactor coolant pump seal leakage is defined as 60 gpm for EPU conditions which is a change from the CLB value of 120 gpm.	2.3.5
Operation of the existing 48-inch main containment purge valves will be prohibited during modes 1 through 4.	2.7.7
The MCNP4A code was used to perform the new fuel storage criticality analysis.	2.8.6.1
The MCNP5 code was used to perform the spent fuel storage criticality analysis.	2.8.6.2

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

Description	LR Section
In the event of a station blackout, a new time limit is required to secure steam generator blowdown within 30 minutes. The new time limit provides inventory conservation with the higher decay heat loads at EPU conditions. This action is included in the existing emergency operating procedures (EOPs), but is not credited in existing analyses.	2.3.5 2.11.1
In the event of a station blackout, a revised time limit is required to supply power, ensure there is a continuous source of water, and start one charging pump within 60 minutes. The new time limit is bounded by the current time frame in which these activities would occur following the steps of the existing EOPs.	2.3.5 2.11.1
The containment hydrogen purge system is being upgraded to provide capability for control room operated online venting. In the event of a containment isolation actuation signal, a new action is required to verify the containment hydrogen purge system isolation valves are closed.	2.7.7 2.11.1
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
Changes are required to update reactor coolant system sub-cooling post-accident pressure-temperature curves. These curves provide a range of limiting conditions to help verify adequate core cooling, during various plant conditions, including support of the low temperature overpressure protection to enable temperatures for 54 effective full power years.	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. Since the hot leg injection path through the auxiliary spray line cannot provide the required flow rate, this flow path is being eliminated as an injection path. Two hot leg injection paths remain available for establishing simultaneous hot leg and cold leg injection.	2.11.1
Accident analysis assumptions are changing for the minimum high pressure safety injection, maximum low pressure safety injection, and containment spray flow rates. 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 and time to boil will decrease as a result of the EPU, due to the increased decay heat.	2.11.1
The safety injection tank pressure is increasing to support the small break LOCA analysis. Tank pressure will be raised to support injection at an earlier time. Associated setpoints for venting, draining and isolating the safety injection tanks will be revised, as required.	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. The current St. Lucie Unit 1 NSSS design parameters are summarized in Tables 4.4-1, 4.4-2, 4.4-3, 4.4-4, and 5.3-1 of the St. Lucie Unit 1 Updated Final Safety Analysis Report (UFSAR). 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 extended power uprate (EPU) represents a core power increase of approximately 11.85% above the current core power of 2700 megawatts thermal (MWt). As a result of the EPU, the NSSS design parameters have been revised as shown in Table 1.1-1. The table provides information for the current design bases conditions and for various cases representing operation following the EPU. These parameters have been incorporated, as required, into the applicable NSSS systems and components evaluations, and 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 subsection.

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, fuel analyses, and evaluations. The codes and methods used to calculate these values have been successfully used to license similar power uprates. They use basic thermal-hydraulic calculations, along with first principles of engineering, to generate the temperatures, pressures, and flows shown in 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 Table 1.1-1.

1. Uprated NSSS power of 3050 MWt, which includes 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. AREVA 14x14 fuel with high thermal performance (HTP) grid design.

4. Core bypass flow of 4.2%.

5. Feedwater temperature range of 409.0°F to 441.0°F.

6. Steam generator tube plugging (SGTP) levels of 0% and 10% average, with a maximum asymmetry of ± 2% of the actual average value between steam generators, and a maximum peak tube plugging level of 12%.

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 industry and regulatory requirements applicable to St. Lucie Unit 1, and that they provide adequate flexibility and margin during plant operation.

1.1.2 Description of Analyses and Evaluation

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 Table 1.1-1 represent parameters based on a reactor vessel inlet temperature of 535.0°F. Case 1 is based on 0% SGTP. Case 2 yielded the minimum secondary side steam generator pressure and temperature since it assumed an average of 10% SGTP. Note that primary side temperatures were identical for these two cases. This is a result of defining the thermal design flow based on 10% SGTP and conservatively applying it to all cases.
- EPU Cases 3 and 4 of 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% SGTP. Case 4 is based on an average of 10% 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 Table 1.1-1 (see 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 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. The results of the best-estimate RCS Flow calculations are as follows:

- Best-estimate RCS flow values of 203,483 gpm/loop at 0% SGTP and 198,803 gpm/loop at 10% SGTP.

These calculated flows demonstrate that adequate flow margin exists for the thermal design flow and the mechanical design flow values.

1.1.4 Conclusion

The resulting PCWG parameters (Table 1.1-1) were used as the basis for the NSSS analytical efforts. 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.

FPL 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 3	Case 4
NSSS power (% current)	100	112	112	112	112
MWt	-	3050(5)	3050(5)	3050(5)	3050(5)
10^6 BTU/hr	-	10,407	10,407	10,407	10,407
Reactor power MWt	2700	3030(4)	3030(4)	3030(4)	3030(4)
10^6 BTU/hr	9215	10,339	10,339	10,339	10,339
Thermal design flow, loop gpm	185,000	187,500(2)	187,500(2)	187,500(2)	187,500(2)
Reactor 10^6lb/hr	139.3	143.8	143.8	140.8	140.8
Reactor coolant pressure, psia	2250	2250	2250	2250	2250
Core bypass, % (analysis value)	3.9	4.2(9)	4.2(9)	4.2(9)	4.2(9)
Reactor coolant temperature, °F					
Core outlet	-	593.3	593.3	608.2	608.2
Vessel outlet	594.0	591.0	591.0	606.0	606.0
Core average	-	565.2	565.2	580.8	580.8
Vessel average	571.3	563.0	563.0	578.5	578.5
Vessel/core inlet	548.5	535.0	535.0	551.0	551.0
Steam generator outlet	548.5	534.6	534.6	550.6	550.6
Steam Generator					
Steam outlet temperature, °F	529.1	513.9	510.9	530.6(6)	527.7
Steam outlet pressure, psia	878	770(1)	750(1)	890(1,6)	868(1)
Steam outlet flow, 10^6 lb/hr total	11.80	12.78/13.36	12.78/13.35	12.84/13.42(6)	12.83/13.40
Feed temperature, °F	432.4	409.0/441.0	409.0/441.0	409.0/441.0	409.0/441.0
Steam outlet moisture, % max.	0.10	0.10	0.10	0.10	0.10
Design fouling factor, hr. sq. ft. °F/Btu	0.00005	0.00005	0.00005	0.00005	0.00005
Tube plugging level (%)	0	0	10(7)	0	10(7)
Zero load temperature, °F	532	532	532	532	532

Table 1.1-1
NSSS PCWG Parameters for St. Lucie Unit 1 EPU

Hydraulic Design Parameters	
Pump design point, flow (gpm)/head (ft.)	81,200/245
Mechanical design flow, loop gpm	438,500
Minimum measured flow, loop gpm	390,000$^{(3)}$

1. 13 psi steam generator internal pressure drop 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 of 908 psia, steam temperature of 533.1°F, and steam flow of 13.43×10^6 lb/hr 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%.
8. Current parameters obtained from Tables 4.4-1, 4.4-2, 4.4-3, 4.4-4, 5.1-1, and 5.3-1 of the UFSAR.
9. EPU analysis conservatively increased bypass assumption to 4.2%.

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. FPL's review primarily focused on the effects of the proposed extended power uprate (EPU) on the reactor vessel surveillance capsule withdrawal schedule, which is discussed in more detail in LR Section 2.1.1.2.1.

The NRC's acceptance criteria are based on:

- 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 nonbrittle 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 RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 in accordance with the ASME Code Section III, and ANSI B 31.7. 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 maintain the stresses within applicable stress limits.

Design pressures, temperatures and transients are listed in Chapter 5 and details of the transient analysis are provided in Chapter 15 of the UFSAR.

Means are provided to detect significant leakage from the RCPB with monitoring readouts and alarms in the control room as discussed in UFSAR Chapters 5 and 12.

The RCPB has provisions for in-service inspection as described in Section 5.2.5, to ensure the structural and leak-tight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with ASTM-E-185 is provided as discussed in Chapter 5.

- 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.

Carbon and low-alloy steel materials which form part of the RCPB meet the requirements of the ASME Code, Section III, paragraph N-330 at a temperature of +40°F. The actual nil-ductility transition temperature (NDTT) of the materials has been determined by drop weight tests in accordance with ASTM-E-208. For the reactor vessel, Charpy tests will be also performed and the results will be used to plot a Charpy transition curve. The NDTT as determined by drop weight test will be used to correlate the Charpy transition curve and establish nonirradiated base points for the surveillance program. See Criterion 32 and Section 5.2.3.5 of the UFSAR.

The combined static and transient loadings are limited, whenever the RCS temperature is below NDTT + 60°F to sufficiently low values to make the probability of a rapidly propagating failure extremely remote.

The RCPB components are constructed in accordance with the applicable codes and comply with the test and inspection requirements of these codes. These test 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 code requirements are performed. The tests and inspection performed on the reactor vessel are summarized in UFSAR Sections 5.4.5 and 5.4.6.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel. The peak vessel neutron fluence at 60 years at 2700 megawatts thermal (MWt) is calculated to be less than 4.7×10^{19} n/cm^2 (E > 1 MeV); the neutron fluence at the limiting vessel material is less than 3.1×10^{19} n/cm^2.

The limiting material is the longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum adjusted reference nil-ductility transition temperature (RT_{NDT}) at 60 years that is below the 10 CFR 50.61 screening limit. A surveillance program will be conducted (see Criterion 36) to allow monitoring of the NDTT shift of the vessel material during its lifetime. Based on the determined NDTT, for a given exposure, operating restrictions to limit vessel stresses would be applied as necessary. The RCS pressure will not be increased above 500 psia until the reactor coolant temperature has been raised to NDTT + 60°F. Vessel stresses resulting from a pressure of 500 psia are sufficiently low to preclude brittle fracture.

During normal start-up for power operation, the reactor will not be made critical until the RCS temperature is at least 120°F greater than the predicted NDTT based on the projected fast neutron fluence to the vessel. The stress criteria include the maximum loads associated with the most severe transients during emergency conditions at operating temperature. This will assure that a reactivity-induced loading which would contribute to elastic or plastic deformation cannot occur below a reactor operating temperature corresponding to NDTT+120°F.

The activation of the safety injection systems will introduce highly borated water into the primary system at pressures significantly below operating pressures and will not cause adverse pressure or reactivity effects.

The thermal stresses induced by the injection of cold water into the vessel have been examined. Analysis shows that there is no gross yielding across the vessel wall using the minimum specified yield strength in the ASME Boiler and Pressure Vessel Code, Section III.

Adverse effects that could be caused by exposure of equipment or instrumentation to containment spray water is avoided by designing the equipment or instrumentation to withstand direct spray or by locating it or protecting it to avoid a direct spray.

The reactor vessel material surveillance program conforms to ASTM-E-185-82 and satisfies the intent of the proposed Appendix H to 10 CFR 50 as published in the Federal Register on July 3, 1971. The differences between the plant surveillance program and the requirements presented in Appendix H are captured in UFSAR Section 5.4.4.

The material surveillance program is implemented to monitor the radiation-induced changes in the mechanical and impact properties of the reactor vessel materials (base metal, weld metal and heat affected-zone metal). Sample pieces taken from the same shell plate material used in fabrication of the reactor vessel are installed between the core and the vessel inside wall. These samples will be removed and tested at intervals during vessel life to provide an indication of the extent of the neutron embrittlement of the vessel wall. Charpy tests will be performed on the samples to develop a Charpy transition curve. By comparing this curve with the Charpy curve and drop weight tests on specimens taken at the beginning of the vessel life, the change to the NDTT will be determined and operating instructions/restrictions to limit vessel stresses would be implemented as necessary.

Compliance with the NRC review criteria associated with 10 CFR 50.60 and Regulatory Guide (RG) 1.190 is discussed in Technical Evaluations Section 2.1.1.2.

In addition to the licensing bases described in the UFSAR, the reactor vessel material surveillance program was evaluated for St. Lucie Unit 1 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 material 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 5.4.4, Material Surveillance Program. The surveillance capsule withdrawal schedule is contained in UFSAR Section 5.4.4. In addition, UFSAR Section 18.2.12 presents 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, and (4) Pressure-Temperature Limit Curves.

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 (UFSAR Section 5.4.4).

2.1.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

EPU Fluence Projections

The EPU would normally 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 fluence because the EPU fluence analysis used a more realistic approach that removed some of the conservatism from the pre-EPU 60-year fluence analysis. 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 after 60 years that made a conservative allowance for the EPU. Vessel fluence projections to 60 years that considered the EPU are compared to the previous values in LR Table 2.1.1-2 at the 0° and 15° azimuthal locations. The 0° location corresponds to the peak fluence for the vessel plates and circumferential. The 15° location corresponds to the peak fluence for the vessel axial welds. Both sets of fluence values are judged sufficiently alike to warrant no change to the schedule in LR Table 2.1.1-1. Therefore, there is no impact of the proposed EPU on the surveillance capsule withdrawal schedule.

The calculated fluence projections used in the EPU evaluation complied with RG 1.190 (Reference 1), including consideration of dosimetry measurements from the tested surveillance capsules. The EOL fluence values were used to calculate adjusted reference temperature (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 on the basis of the copper and nickel content of those same materials. The results of the most recent assessment as documented in WCAP-15446 (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 under at the EPU power 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 548.5°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 life time 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 4). 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 525°F to 590°F after the EPU, the equations and methodology of RG 1.99, Revision 2 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 following 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. Three surveillance capsules have been tested to date. Two more are scheduled for evaluation. There is an additional standby capsule 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, 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 2.1.1-2. The pre-EPU vessel fluence projections are comparable because of the assumptions used (e.g., provision for an uprate). The fluence projections presented in LR Table 2.1.1-1 for the two capsules scheduled for removal after 38 and 45 EFPY reflect the EPU conditions.

The surveillance capsule withdrawal schedule for St. Lucie Unit 1 given in LR Table 2.1.1-1 is consistent with ASTM E 185-82 and provides for monitoring through the 60-year operating period. 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. Three 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 the T_{cold} will continue to be within the range 525°F to 590°F after the EPU, the equations and methodology of RG 1.99, Revision 2 will remain valid.

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 EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.1.4 References

1. U.S. NRC Document, Regulatory Guide (RG) 1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001.

2. WCAP-15446, Revision 1, Analysis of Capsule 2840 from the Florida Power & Light Company St. Lucie Unit 1 Reactor Vessel Radiation Surveillance Program, January 2002. (Submitted to the NRC by FPL Letter L-2002-082 Dated May 2, 2002.)

3. U.S. NRC Document, Regulatory Guide (RG) 1.99, Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, May 1988.

4. U.S. NRC Document, 10 CFR 50.61, Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," Federal Register, Volume 60, No. 143, dated December 19, 1995, effective January 18, 1996.

Table 2.1.1-1
Surveillance Capsule Withdrawal Schedule for 60 Years

Capsule Location	Capsule Lead Factor[1,6]	Approximate Removal Time (EFPY)[1]	Neutron Fluence (n/cm^2)	Updated[6] Neutron Fluence (n/cm^2)
97°	----	4.67[1,2]	5.91×10^{18}[2]	5.174×10^{18}[2]
104°	----	9.515[1,2]	9.18×10^{18}[2]	7.885×10^{18}[2]
284°	----	17.23[1,2]	1.45×10^{12}[2]	1.243×10^{19}[2]
263°	1.34	38[1,3]	4.24×10^{19}[2]	3.79×10^{19}[3]
83°	1.34	45[1,4]	4.98×10^{19}[1,4]	4.60×10^{19}[4]
277°	1.34	Standby	(5)	(5)

1. From UFSAR Table 5.4-3, removal time is EFPY from plant startup.
2. Value reported in WCAP-15446 (Reference 2); capsule evaluation completed.
3. Capsule 263° is projected to reach the 60-year vessel inside diameter (ID) fluence at approximately 38 EFPY.
4. Capsule 83° is projected to reach one to two times the 60-year vessel ID fluence at approximately 45 EFPY.
5. Capsule 277° is designated as "standby".
6. Capsule lead factor and fluence updated for EPU.

Table 2.1.1-2
Comparison of Peak 0° and 15° Azimuth Vessel ID Fluence Values at 52 EFPY

Source	Azimuthal Location	Surface (n/cm^2, E > 1.0 MeV)
Pre-EPU	0°	4.24E+19
EPU Analysis	0°	4.036E+19
Pre-EPU	15°	2.81E+19
EPU Analysis	15°	2.630E+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]
97°	C-8-2[2]	63.83	5.174E+18	0.815984	0.665831	52.08	
97°	C-8-2[3]	68.7	5.174E+18	0.815984	0.665831	56.06	
104°	C-8-2[3]	79.87	7.885E+18	0.933339	0.871122	74.55	
284°	C-8-2[2]	84.99	1.243E+19	1.060619	1.124913	90.14	
284°	C-8-2[3]	87.93	1.243E+19	1.060619	1.124913	93.26	82.22[4]
97°	Weld 9-203	72.34	5.174E+18	0.815984	0.665831	59.03	
104°	Weld 9-203	67.4	7.885E+18	0.933339	0.871122	62.91	
284°	Weld 9-203	68	1.243E+19	1.060619	1.124913	72.12	72.90[5]

1. CF is chemistry factor.
2. Transverse plate orientation.
3. Longitudinal plate orientation.
4. Best fit CF determined for plate C-8-2 results (combined orientations).
5. CF determined for weld 9-203.

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. FPL's review of P-T limits covered the P-T limits methodology and the calculations for the number of effective full-power years (EFPY) specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

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

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

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

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 in accordance with the ASME Code Section III, and ANSI B 31.7. Quality control, inspection, and testing as required by this standard and allowable reactor pressure temperature operations 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 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.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel. The peak vessel neutron fluence at 60 years at 2700 MWth is calculated to be less than 4.7×10^{19} n/cm^2 (E > 1 MeV); the neutron fluence at the limiting vessel material is less than 3.1×10^{19} n/cm^2.

The limiting material is the longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum adjusted reference nil-ductility transition temperature (RT_{NDT}) at 60 years that is below the 10 CFR 50.61 screening limit. A surveillance program will be conducted (see Criterion 36) to allow monitoring of the nil-ductility transition temperature (NDTT) shift of the vessel material during its lifetime. Based on the determined NDTT, for a given exposure, operating restrictions to limit vessel stresses would be applied as necessary. The RCS pressure will not be increased above 500 psia until the reactor coolant temperature has been raised to NDTT + 60°F. Vessel stresses resulting from a pressure of 500 psia are sufficiently low to preclude brittle fracture.

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.

UFSAR Section 5.4.2 indicates that reactor vessel heatup, cooldown and hydrostatic test P-T limits have been calculated in accordance with ASME Boiler and Pressure Vessel Code Section III, Appendix G to the 1986 Edition. The heatup, cooldown and system hydro test P-T limit curves are based on the requirement in Appendix G of 10 CFR 50 that in no case when the core is critical, other than for the purpose of low-power level physics tests, will the temperature of the reactor vessel be made lower than the minimum permissible temperature for the in-service system hydrostatic pressure test nor less than 40°F above that temperature required by ASME Code Section IV.A.2 of Appendix G of 10 CFR 50.

In addition to the licensing bases described in the UFSAR, the P-T limits and USE for the RCPB were evaluated for St. Lucie Unit 1 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 Sections 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 for 35 EFPY meet the requirements of 10 CFR 50 Appendix G and 10 CFR 50.61.

The current licensing basis for the P-T limit curves is for 35 EFPY and can be found in Reference 9. New limits have been generated in conjunction with the EPU for 54 EFPY.

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) assessment of USE.

2.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The EPU would normally result in an increase to the neutron fluence on the reactor pressure vessel. As shown in LR Section 2.1.1, Table 2.1.1-2, there was actually a small decrease in the projected 60-year fluence based on 52 EFPY. That occurred because the EPU fluence analysis used more recent core power histories that enabled removal of excess conservatism from the pre-EPU 60-year fluence analysis, while adding a 10% factor of conservatism to the EPU fluence projections beginning with Cycle 25. The effect of the projected changes in operating conditions on reactor vessel integrity was evaluated. The vessel fluence projections for the St. Lucie Unit 1 plant life of 60 years are presented in LR Table 2.1.2-1, Peak EOL Vessel Fluence Values at 0° and 15° Azimuths. The 0° and 15° azimuths correspond to the peak fluence locations for the base metal and circumferential weld (0°) and the axial welds (15°). Vessel fluence is provided for the vessel inside surface (clad-base metal interface) and for the 1/4 and 3/4 thickness (T) locations.

Neutron fluence values are used to calculate the EOL adjusted reference temperature (ART) and the EOL USE using the guidance from Regulatory Guide (RG) 1.99 Revision 2 (Reference 1). The projected fluence values at three different EFPY levels are provided in LR Table 2.1.2-1: 35 EFPY, 52 EFPY, and 54 EFPY. The current P-T limit curves are applicable to 35 EFPY (Reference 9). The 60-year USE projections are based on the fluence at 52 EFPY. New 60-year P-T limits have been generated based on the fluence projected to 54 EFPY to provide margin for fuel management. Appendix G to this LR provides WCAP-17197. 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 548.5°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 negligible.

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 5) 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. Those CF values were reported in RVID-2 (Reference 5) and updated in Reference 6. Position 2.1 determines CF values based on the St. Lucie Unit 1 reactor vessel surveillance capsule results. The post-irradiation measurements for plate C-8-2 and weld 9-203 from Reference 7 and updated capsule fluence values as shown in LR Table 2.1.2-3. LR Table 2.1.2-4 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 C-8-1 and C-8-3 and to weld 9-203.

The current P-T limit curves applicable to 35 EFPY in Reference 9 use a value of lowest service temperature (LST) of 190°F. As input to the 60-year (54 EFPY) P-T limit curve determination, a reassessment was performed of the basis for the LST and resulted in a revised value of 158°F.

Projected ART values were determined for each of the reactor vessel beltline materials using a conservative estimate of neutron fluence at 60 years based on 54 EFPY. Projected USE values were determined for each of the reactor vessel beltline materials using a conservative estimate of neutron fluence at 60 years based on 52 EFPY. Each of the neutron fluence projections includes a 10% factor of conservatism beginning with Cycle 25 to accommodate future changes in core power distribution.

For the P-T limit curves acceptance criteria, the P-T limits are developed in accordance with 10 CFR 50, Appendix G, are applicable after implementation of the EPU and the period of applicability extends beyond the date the EPU is implemented.

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, and state: "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 1 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 post-EPU ART projections exceed the values used for the current P-T limit curves, then a new applicability date for the current P-T limit curves must be established using the EPU fluence projections. The current P-T limit curves are applicable to 35 EFPY (Reference 9). New P-T limits have been generated for operation to 60 years (based on 54 EFPY fluence projection). See LR Appendix G, WCAP-17197.

The effect of the EPU on the applicability of the current P-T limits curves was evaluated by comparing the ART values for the current licensing basis with the ART values after the EPU. These values were calculated using the current licensing basis fluence projections and the EPU fluence projections. The EPU fluence projections for the 1/4T and 3/4T locations in the vessel at the 0° and 15° azimuths are given in LR Table 2.1.2-1, Peak EOL Vessel Fluence Values at 0° and 15° Azimuths.

As input to the 60 year (54 EFPY) P-T limit curve determination, a reassessment of the basis for the LST was performed. The LST is defined by ASME Article NB-2332 (Reference 10) as, at a minimum, equal to the limiting RT_{NDT} + 100°F for piping, pump, and valve materials (excluding bolting). The basis for the current P-T limit curve (Reference 9) LST value of 190°F was determined to be too conservative and, therefore, revised to a value of 158°F. It was concluded that the highest RT_{NDT} for the piping, pump and valve material was 58°F, with the piping having the limiting RT_{NDT}.

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. 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. Otherwise, no additional analysis 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 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 current 35 EFPY bases (Reference 9) at 35 EFPY. ART values were projected for 35, 52, and 54 EFPY for the 1/4T and 3/4T locations. The ART values that are the basis for the current P-T Limits are greater than the ART values projected for 35 EFPY that account for the affects of the EPU. Thus, the current P-T limits (Reference 9) remain valid for at least 35 EFPY and it is not necessary to reduce the current period of applicability. The ART values projected for 52 EFPY and for 54 EFPY reflect values at 60 years with margin. The 54 EFPY ART values and the revised LST value were used to generate new P-T limits for operation to 60 years.

USE

LR Table 2.1.2-7, Projected 60 Year USE Values for the Beltline Region Materials contains the results of the USE projections for the St. Lucie Unit 1 beltline region materials. These results were calculated using the EPU 1/4T fluence projections for 52 EFPY. All of the beltline materials are projected to have a USE greater than 50 ft-lb through EOL (52 EFPY) in compliance with 10 CFR 50, Appendix G. As shown in Table 2.1.2-7, the intermediate shell plate C-7-3 has the lowest projected USE of 57.4 ft-lbs at 52 EFPY. Since USE values greater than 50 ft-lb could be demonstrated through EOL it was not necessary to perform an equivalent margins analysis.

Inlet Temperature

The T_{cold} will be maintained at a value of 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 concludes that it has addressed changes in neutron fluence and their effects on P-T limits and USE. FPL further concludes that St. Lucie Unit 1 has demonstrated the validity of the proposed P-T limits for operation under the proposed EPU conditions. Based on this, FPL concludes that the proposed 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 1 to continue to meet its current licensing basis with respect to the GDC-14 and GDC-31 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU is acceptable with respect to the proposed P-T limits and USE.

2.1.2.4 References

1. NRC Regulatory Guide 1.99, Revision 2, Radiation Embrittlement of Reactor Vessel Materials, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1988.

2. WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006.

3. NRC Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.

4. NRC Letter to Florida Power & Light, St. Lucie Unit 1 – Issuance of Amendment Re: Reactor Coolant System Pressure/Temperature Limits (TAC No. M92412), October 27, 1995 (Amendment 141).

5. NRC Reactor Vessel Integrity Database, Version 2.0.1 (RVID-2), July 6, 2000.

6. Florida Power & Light Letter, L-97-223, St. Lucie Units 1 and 2 Docket Nos. 50-335 and 50-389 NRC Reactor Vessel Integrity Generic Letter 92-01 Revision 1 Updated Information, August 28, 1997.

7. Westinghouse Report, WCAP-15446, Revision 1, Analysis of Capsule 284o from the Florida Power and Light Company St. Lucie Unit 1 Reactor Vessel Radiation Surveillance Program, January 2002.

8. Westinghouse Report, WCAP-15571, Revision 1, Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program, April 18, 2008.

9. Florida Power & Light Letter, L-2004-244, St. Lucie Unit 1 Docket No. 50-335 Proposed License Amendment Extension of the Reactor Coolant System Pressure/Temperature Curve Limits and LTOP to 35 EFPY, August 28, 1997.

10. ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection NB, 2004 Edition.

Table 2.1.2-1
Peak EOL Vessel Fluence Values at 0° and 15° Azimuths

EFPY	Azimuthal Location	Fluence at Clad-Base Metal Interface (n/cm^2, E > 1.0 MeV)	1/4T Fluence (n/cm^2, E > 1.0 MeV)	3/4T Fluence (n/cm^2, E > 1.0 MeV)
35	0°	2.573E+19	1.534E+19	5.448E+18
35	15°	1.659E+19	9.888E+18	3.512E+18
52	0°	4.036E+19	2.405E+19	8.545E+18
52	15°	2.630E+19	1.567E+19	5.568E+18
54	0°	4.208E+19	2.508E+19	8.909E+18
54	15°	2.744E+19	1.635E+19	5.810E+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(2)	Position 2.1(2)
Intermediate Shell Plate	C-7-1	0°F	74.6	---
Intermediate Shell Plate	C-7-2	-10°F	74.6	---
Intermediate Shell Plate	C-7-3	10°F	73.8	---
Lower Shell Plate	C-8-1	20°F	---	81.80
Lower Shell Plate	C-8-2	20°F	---	82.22
Lower Shell Plate	C-8-3	0°F	---	62.68
Intermediate to Lower Shell Girth Weld	9-203 (Heat 90136)	-60°F	---	84.97
Intermediate Shell Axial Weld	2-203 A/C (Heats A-8746 and 34B009)	-56°F(1)	90.7	---
Lower Shell Axial Weld	3-203 A/C (Heat 305424)	-60°F	188.8	---

1. Generic value for CE weld.
2. Positions 1.1 and 2.1 from Regulatory Guide 1.99, Revision 2 (Reference 1).

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

From Table 5-14 of CN-MRCDA-08-40 Capsule Location	Material and Orientation	Measured Shift (°F)	Neutron Fluence (n/cm^2)	Fluence Factor	FF^2	Shift x FF
97°	C-8-2[1]	63.83	5.174E+18	0.815984	0.665831	52.08
97°	C-8-2[2]	68.7	5.174E+18	0.815984	0.665831	56.06
104°	C-8-2[2]	79.87	7.885E+18	0.933339	0.871122	74.55
284°	C-8-2[1]	84.99	1.243E+19	1.060619	1.124913	90.14
284°	C-8-2[2]	87.93	1.243E+19	1.060619	1.124913	93.26
Best Fit CF for Plate C-8-2 = 82.22						
97°	Surveillance Weld 9-203	72.34	5.174E+18	0.815984	0.665831	59.03
104°	Surveillance Weld 9-203	67.4	7.885E+18	0.933339	0.871122	62.91
284°	Surveillance Weld 9-203	68	1243E+19	1.060619	1.124913	72.12
Best Fit CF for Weld = 72.90						

1. Transverse plate orientation.
2. Longitudinal plate orientation.

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

RAI # 384, 385, 427, 607, 3344From Tables 4-3, 4-5 and 5-15 of CN-MRCDA-08-40 Material	Copper and Nickel Content (%)	Chemistry Factor	Chemistry Factor Ratio	Chemistry Factor from Surveillance Data	Best Fit CF(1)
C-7-1	0.11, 0.64	74.60(2)	n/a	n/a	n/a
C-7-2	0.11, 0.64	74.60(2)	n/a	n/a	n/a
C-7-3	0.11, 0.58	73.80(2)	n/a	n/a	n/a
C-8-1	0.15, 0.56	107.80(2)	0.9949	82.22	81.80
C-8-2	0.15, 0.57	79.53(2)	1.0	82.22	82.22
C-8-3	0.12, 0.58	82.60(2)	0.7623	82.22	62.68
2-203 A/C	0.19, 0.09	90.65(2)	n/a	n/a	n/a
3-203 A/C	0.27, 0.63	188.8(3)	n/a	n/a	n/a
Surveillance Weld	0.23, 0.07	n/a	1.0	72.90	72.90
9-203 Weld	0.27, 0.07	84.36(2)	1.1656	72.90	84.97

1. The best fit CF is the product of the CF ratio and the CF from surveillance data.
2. Value from RVID-2 (Reference 5).
3. Value from Reference 6.

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

RAI #384, 385, 1555, 3324Table 4-3 of CN-MRCDA-08-40. Material Description	Material Heat Number	Copper (%)	Initial USE
Intermediate Shell Plate C-7-1	A-4567-1	0.11	81.9 ft-lb(1)
Intermediate Shell Plate C-7-2	B-9427-1	0.11	81.9 ft-lb(1)
Intermediate Shell Plate C-7-3	A-4567-2	0.11	76.05 ft-lb(1)
Lower Shell Plate C-8-1	C-5935-1	0.15	81.9 ft-lb(1)
Lower Shell Plate C-8-2	C-5935-2	0.15	103 ft-lb(2)
Lower Shell Plate C-8-3	C-5935-3	0.12	88.4 ft-lb(1)
Intermediate to Lower Shell Girth Weld 9-203	90136	0.27	144 ft-lb(2)
Intermediate Shell Axial Weld 2-203 A/C	A-8746 and 34B009	0.19	102.3 ft-lb(3)
Lower Shell Axial Weld 3-203 A/C	305424	0.27	112 ft-lb(4)

1. Determined based on 65% of the measured value for longitudinally-oriented specimens.
2. Value determined based on the measured value for transversely-oriented specimens.
3. Value based on the average of the generic data as reported in RVID-2 (Reference 5).
4. Value based on sister plant data (Reference 8).

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

RAI #385, 1556Table 5-6 of CN-MRCDA-08-40. EFPY	1/4T Limiting ART	3/4T Limiting ART
Lower Shell Axial Welds, 3-203 A/C		
35 (EPU)(1)	184°F	130°F
52 (EPU)(1)	208°F	154°F
54 (EPU)(1)	210°F	156°F
Current Basis(2)	191°F	137°F

1. 35 EFPY (EPU) is the EPU-adjusted projection for a time corresponding approximately to the current P-T curve basis (Reference 9). 52 and 54 EFPY (EPU) are two conservative EPU-adjusted projections for 60 years of operation.
2. Projected values for Amendment 196 P-T Limits for the current 35 EFPY-pre EPU (Reference 9).

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

RAI #384, 1208, 1275, 1283, 1555, 3324Table 5-8 of CN-MRCDA-08-40. Reactor Vessel Beltline Material	Cu Wt %	1/4T EOL Fluence (E+19 n/cm2)	Unirradiated USE (ft-lb)	Projected USE Decrease(1) (%)	Projected EOL USE (ft-lb)
C-7-1	0.11	2.41	81.9	24.5	61.8
C-7-2	0.11	2.41	81.9	24.5	61.8
C-7-3	0.11	2.41	76.05	24.5	57.4
C-8-1	0.15	2.41	81.9	29.7	57.6
C-8-2	0.15	2.41	103	29.7	72.4
C-8-3	0.12	2.41	88.4	25.8	65.6
9-203	0.27	2.41	144	48	74.9
2-203 A/C	0.19	1.57	102.3	36	65.5
3-203 A/C	0.27	1.57	112	44.3	62.4

1. Calculated in accordance with Regulatory Guide 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. FPL's review covered the PTS methodology and the calculations for the nil-ductility reference temperature, (RT_{PTS}), at the expiration of the license, considering neutron embrittlement effects.

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

- 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 abnormal leakage, of rapidly propagating fracture, and of gross rupture;
- GDC-31, insofar as it requires that the reactor coolant pressure boundary be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized;
- 10 CFR 50.61, insofar as it sets fracture toughness criteria for protection against PTS events.

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

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The St. Lucie Unit 1 specific GDCs 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 in accordance with the ASME Code Section III, and ANSI B 31.7. Quality control, inspection, and testing as required by this standard and allowable reactor pressure temperature operations 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 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.

The combined static and transient loadings are limited, whenever the reactor coolant system temperature is below nil-ductility transition temperature (NDTT) + 60°F to sufficiently low values to make the probability of a rapidly propagating failure extremely remote.

The limiting material is the longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum RT_{PTS} (initial RT adjusted by the predicted transition temperature shift plus margin) at 60 years that is below the 10 CFR 50.61 screening limit. A reactor vessel surveillance program will be conducted (see Criterion 36) to allow monitoring of the transition temperature shift of the vessel material during its lifetime. Based on the determined adjusted reference temperature, (ART) (initial RT adjusted by the predicted transition temperature shift plus margin), for a given exposure, operating restrictions to limit vessel stresses would be applied, as necessary. The reactor coolant system pressure will not be increased above 500 psia until reactor coolant temperature has been raised to NDTT+60°F. Vessel stresses resulting from a pressure of 500 psia are sufficiently low to preclude brittle fracture.

During normal start-up for power operation, the reactor will not be made critical until the reactor coolant system temperature is at least 120°F greater than the predicted nil ductility transition temperature based on plant records of fast neutron dose to the vessel. The stress criteria include the maximum loads associated with the most severe transients during emergency conditions at operating temperature. This will assure that a reactivity-induced loading which would contribute to elastic or plastic deformation cannot occur below a reactor operating temperature corresponding to NDTT+120°F.

The thermal stresses induced by the injection of cold water into the vessel have been examined. Analysis shows that there is no gross yielding across the vessel wall using the minimum specified yield strength in the ASME Boiler and Pressure Vessel Code, Section III.

- 10 CFR 50.61, Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, are described in UFSAR Section 18.3.1.1 as follows:

  The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized-water reactors (PWR). Licensees are required to perform an assessment of the projected values of the maximum 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 pressurized thermal shock 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).

In addition to the licensing bases described in the UFSAR, PTS was evaluated for St. Lucie Unit 1 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

Pressurized thermal shock is discussed in UFSAR Section 18.3.1.1, Pressurized Thermal Shock and in the License Renewal SER, NUREG-1779 Section 4.2.2 (Reference 1). In addition, UFSAR Section 18.2.12 describes the Reactor Vessel Integrity Program, designed to manage reactor vessel embrittlement, which encompasses the following subprograms: (1) Reactor Vessel Surveillance Capsule Removal and Evaluation, (2) Fluence and Uncertainty Calculations, (3) Monitoring Effective Full Power Years, and (4) Pressure-Temperature Limit Curves.

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 extended power uprate (EPU) have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the end-of-license 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 would normally result in an increase to the neutron fluence on the reactor pressure vessel. As shown in LR Section 2.1.1, Table 2.1.1-2, Comparison of Peak 0° and 15° Azimuth Vessel ID Fluence Values at 52 EFPY, there was actually a decrease of the fluence because the EPU fluence analysis used a more realistic approach that removed some of the conservatism from the pre-EPU 60-year fluence analysis. The effect of this projected change on reactor vessel integrity was evaluated. The vessel fluence projections for the 60-year life (approximately 52 effective full-power years, EFPY) are presented in LR Table 2.1.3-1, Peak EOL Vessel Fluence Values at 0° and 15° Azimuths. The 0° and 15° azimuths correspond to the peak fluence locations for the base metal and circumferential weld (0°) and the axial welds (15°). Neutron fluence values are used to calculate the end-of-life RT_{PTS} using the methods from 10 CFR 50.61. The neutron fluence for St. Lucie Unit 1 was determined using NRC approved methodology (Reference 2) that follows the guidance and meets the requirements of Regulatory Guide (RG) 1.190 (Reference 3).

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 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 5) and were used together with the ΔRT_{PTS} and margin to determine the end-of-life RT_{PTS}. The CF values were determined following Position 1.1 or 2.1 of Reference 4. The Position 1.1 CF values were determined using the best-estimate copper and nickel contents for the beltline materials as reported in RVID-2 (Reference 7) and updated in Reference 6. LR Table 2.1.3-3 provides the determination of the Position 2.1 CF values based on the reactor vessel surveillance data (plate C-8-2 and weld 9-203). LR Table 2.1.3-4 shows the analysis for adjusting those results by the ratio of the chemistry factors to the vessel beltline plates C-8-1 and C-8-3 and weld 9-203.

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 548.5°F to 551°F with 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 10 CFR 50.61 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 negligible.

Assumptions

Projected RT_{PTS} values were determined for each of the reactor vessel beltline materials using values of neutron fluence at 60 years (52 EFPY). The neutron fluence projection was conservatively based to accommodate future changes in core power distribution.

Acceptance Criteria

Acceptance criteria require that the RT_{PTS} values for the 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 (52 EFPY). St. Lucie Unit 1 meets these screening criteria.

For T_{cold}, the acceptance criteria are provided in RG 1.99, Revision 2 (Reference 4), 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 1 meets these acceptance criteria for temperature conditions as described above in the input parameters section of this document.

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
- 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 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 Regulatory Guide 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

- 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.

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

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.

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

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

σ_Δ is the standard deviation for ΔRT_{PTS}.

Where,

σ_u = 0°F when $RT_{NDT(U)}$ is a measured value

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

For plates and forgings:

σ_Δ = 17°F when surveillance capsule data are not used

σ_Δ = 8.5°F when surveillance capsule data are used

For welds:

σ_Δ = 28°F when surveillance capsule data are not used

σ_Δ = 14°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.

$$\Delta RT_{PTS} = CF * f^{(0.28 - 0.10 \log f)} \qquad \text{Equation 3}$$

CF (°F) is the chemistry factor, a function of copper and nickel content determined from Tables 1 and 2 of 10 CFR 50.61.

"f" is the calculated neutron fluence, in units of 10^{19} n/cm^2 (E > 1.0 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 52 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.

$$CF = \frac{\sum[A_i * f_i^{(0.28 - 0.10\log f_i)}]}{\sum[f_i^{(0.56 - 0.20\log f_i)}]} \qquad \text{Equation 4}$$

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.

RT_{PTS} values calculated for the reactor vessel beltline materials at fluence values (E > 1.0 MeV) projected for 60 years (52 EFPY) are presented in LR Table 2.1.3-5, RT_{PTS} Calculations for Beltline Region Materials after 52 EFPY." The highest projected value of RT_{PTS} is 234°F and corresponds to the lower shell axial weld 3-203 A/C.

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 C-8-1, C-8-2 and C-8-3 and weld 9-203. The surveillance data were determined to be credible and were applied to the calculation of the RT_{PTS} values. As part of the PTS assessment, consideration was also given to the weld data from the Beaver Valley Unit 1 surveillance program (Reference 8). The Beaver Valley Unit 1 surveillance weld was used as the basis for the best-estimate copper and nickel content for St. Lucie Unit 1 lower shell axial weld 3-203 A/C. The surveillance data demonstrated that the weld material responded as predicted to neutron irradiation. The Beaver Valley Unit 1 surveillance weld results resulted in a lower derived CF (178.4°F) than that used for St. Lucie Unit 1 (188.8°F) for the RT_{PTS} projections in LR Table 2.1.3-5. The CF adjustments based on St. Lucie Unit 1 surveillance data are summarized in LR Table 2.1.3-4.

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

As discussed above, PTS is 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. 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.

2.1.3.2.5 Results

An evaluation of the impact of the EPU on PTS was performed for St. Lucie Unit 1. RT_{PTS} projections were made for the beltline materials of the St. Lucie Unit 1 reactor vessel under EPU conditions using 10 CFR 50.61. The results of these calculations are presented in LR Table 2.1.3-5. The limiting material for St. Lucie Unit 1 at 60 years (52 EFPY) is the lower shell axial weld 3-203 A/C. The St. Lucie Unit 1 limiting value of RT_{PTS} is 234°F. This result is below the RT_{PTS} screening criterion of 270°F for axially-oriented welds and plates. Based on these results, all RT_{PTS} values are projected to remain below the NRC screening criteria through 60 years (52 EFPY) for St. Lucie Unit 1. Therefore, it is not necessary to perform a plant-specific PTS safety assessment following Regulatory Guide 1.154 (Reference 9).

2.1.3.3 Conclusion

FPL has reviewed the evaluation of the effects of the proposed EPU on the PTS for St. Lucie Unit 1 and concludes that St. Lucie Unit 1 has adequately addressed changes in neutron fluence and their effects on PTS. FPL further concludes that St. Lucie Unit 1 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. Therefore, FPL finds the proposed EPU acceptable with respect to PTS.

2.1.3.4 References

1. 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. WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006.

3. NRC Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.

4. NRC Regulatory Guide 1.99, Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, May 1988.

5. NRC Reactor Vessel Integrity Database, Version 2.0.1 (RVID-2), July 6, 2000.

6. Florida Power & Light Letter, L-97-223, St. Lucie Units 1 and 2 Docket Nos. 50-335 and 50-389 NRC Reactor Vessel Integrity Generic Letter 92-01 Revision 1 Updated Information, August 28, 1997.

7. Westinghouse Report, WCAP-15446, Analysis of Capsule 284o from the Florida Power & Light Company St. Lucie Unit 1 Reactor Vessel Radiation Surveillance Program, January 2002 (submitted to the NRC by FPL Letter L-2002-082, May 2, 2002).

8. Westinghouse Report, WCAP-15571, Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program, April 18, 2008.

9. NRC Regulatory Guide 1.154, Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, January 1987.

Table 2.1.3-1
Peak EOL Vessel Fluence Values at 0° and 15° Azimuths

EFPY[1]	Azimuthal Location	Fluence at Clad-Base Metal Interface (n/cm^2, E > 1.0 MeV)
52	0°	4.036E+19
52	15°	2.630E+19
1. EFPY – Effective Full Power Years; 60 years corresponds to approximately 52 EFPY.		

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

Beltline Materials	Code Number	Initial RT_{NDT}(1)	Chemistry Factor	
			Position 1.1(3)	Position 2.1(3)
Intermediate Shell Plate	C-7-1	0°F	74.6	---
Intermediate Shell Plate	C-7-2	-10°F	74.6	---
Intermediate Shell Plate	C-7-3	10°F	73.8	---
Lower Shell Plate	C-8-1	20°F	---	81.80
Lower Shell Plate	C-8-2	20°F	---	82.22
Lower Shell Plate	C-8-3	0°F	---	62.68
Intermediate to Lower Shell Girth Weld	9-203 (Heat 90136)	-60°F	---	84.97
Intermediate Shell Axial Weld	2-203 A/C (Heats A-8746 and 34B009)	-56°F(2)	90.7	---
Lower Shell Axial Weld	3-203 A/C (Heat 305424)	-60°F	188.8	---

1. Measured value unless stated otherwise.
2. Generic value for CE weld.
3. Positions 1.1 and 2.1 from Regulatory Guide 1.99, Revision 2 (Reference 4).

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

Capsule Location	Material and Orientation	Measured Shift (°F)	Neutron Fluence (n/cm^2)	Fluence Factor	FF^2	Shift x FF
97°	C-8-2(1)	63.83	5.174E+18	0.815984	0.665831	52.08
97°	C-8-2(2)	68.7	5.174E+18	0.815984	0.665831	56.06
104°	C-8-2(2)	79.87	7.885E+18	0.933339	0. 871122	74.55
284°	C-8-2(1)	84.99	1.243E+19	1.060619	1. 124913	90.14
284°	C-8-2(2)	87.93	1.243E+19	1.060619	1. 124913	93.26
Best Fit CF for Plate C-8-2 = 82.22						
97°	Weld 9-203	72.34	5.174E+18	0.815984	0.665831	59.03
104°	Weld 9-203	67.4	7.885E+18	0.933339	0. 871122	62.91
284°	Weld 9-203	68	1.243E+19	1.060619	1. 124913	72.12
Best Fit CF for Weld = 72.90						

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)
C-7-1	0.11, 0.64	74.60(2)	n/a	n/a	n/a
C-7-2	0.11, 0.64	74.60(2)	n/a	n/a	n/a
C-7-3	0.11, 0.58	73.80(2)	n/a	n/a	n/a
C-8-1	0.15, 0.56	107.80(2)	0.9949	82.22	81.80
C-8-2	0.15, 0.57	79.53(2)	1.0	82.22	82.22
C-8-3	0.12, 0.58	82.60(2)	0.7623	82.22	62.68
2-203 A/C	0.19, 0.09	90.65(2)	n/a	n/a	n/a
3-203 A/C	0.27, 0.63	188.8(3)	n/a	n/a	n/a
Surveillance Weld	0.23, 0.07	n/a	1.0	72.90	72.90
9-203 Weld	0.27, 0.07	84.36(2)	1.1656	72.90	84.97

1. The best fit CF is the product of the CF ratio and the CF from surveillance data.
2. Value from RVID-2 (Reference 5).
3. Value from Reference 6.

Table 2.1.3-5

RT_{PTS} Calculations for Beltline Region Materials after 52 EFPY[5]

Reactor Vessel Beltline Material	CF[1] (°F)	Fluence[2] (E19 n/cm^2)	FF[2]	ΔRT_{PTS} (°F)	RT_{NDT}[1] (°F)	σ_U (°F)	σ_Δ (°F)	M[3] (°F)	RT_{PTS}[4] (°F)
C-7-1	74.6	4.036	1.358153	101	0	0	17	34	135
C-7-2	74.6	4.036	1.358153	101	-10	0	17	34	125
C-7-3	73.8	4.036	1.358153	100	10	0	17	34	144
C-8-1	81.80	4.036	1.358153	111	20	0	8.5	17	148
C-8-2	82.22	4.036	1.358153	112	20	0	8.5	17	149
C-8-3	62.68	4.036	1.358153	85	0	0	8.5	17	102
9-203	84.97	4.036	1.358153	115	-60	0	14	28	83
2-203 A/C	90.7	2.630	1.258784	114	-56	17	28	65.5	124
3-203 A/C	188.8	2.630	1.258784	238	-60	0	28	56	234

1. From Table 2.1.3-2.
2. Fluence from Table 2.1.3-1.
3. Margin (M) from Equation 2.
4. From Equation 1.
5. EFPY – Effective Full Power Years; 60 years corresponds to approximately 52 EFPY.

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)). FPL's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination (NDE) procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internal and core support materials are based on 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 Westinghouse Topical Report WCAP-14577, Rev. 1, *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 1.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the reactor vessel internals and core support structure materials 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.

All 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 Class 1. 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 are 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 SSCs is discussed in (UFSAR) Section 3.2.

UFSAR Section 4.2.2.1 states that the reactor vessel internals (RVI) are divided into four major parts consisting of the core support barrel, the lower core support structure and core shroud, the upper guide structure and control element assembly (CEA) shrouds, and the incore instrumentation guide tubes. The materials 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 designed to remain captured in the event of a single failure. Structural fastener material is typically a high strength austenitic stainless steel. However, in 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. Detailed descriptive information pertaining to the RVI is presented in UFSAR Section 4.2.2.2.

The codes adhered to and component classifications are listed in UFSAR Table 5.2-1 and conform to 10 CFR 50.55a.

The 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 presents additional information related to material specifications, weld control, NDE, corrosion resistance, and susceptibility to degradation in LR Section 2.1.4.2. WCAP-14577 does not apply in its entirety to CE designed internals, therefore, only the applicable information was applied to St. Lucie Unit 1.

In addition to the licensing basis described in the UFSAR, the reactor internals and core support materials were evaluated for St. Lucie Unit 1 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 4.2.2.1 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 (SS), with Type 304 being the most common grade. High-strength precipitation-hardening austenitic SS was used for some threaded structural fastener (TSF) applications. Solution annealed Type 316 was also used in fastener 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. Type 403 stainless steel (SS) was used for the upper internals hold down ring. There are no applications of nickel-base Alloy 600 or weld metals Alloys 82 or 182 in the RVI components. 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 chemical 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 change the manner in which 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 SS,

C. Irradiation-enhanced embrittlement,

D. Irradiation-assisted stress corrosion cracking (IASCC) of austenitic SS,

E. Irradiation-induced void swelling of austenitic SS,

F. Thermal aging (embrittlement) of cast austenitic SS (CASS), and

G. Irradiation-enhanced stress relaxation of threaded structural fasteners (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 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 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 2.1.4-1 shows an increase in the peak steady-state core outlet temperature to 608.2°F from the current temperature of 594°F and the core inlet temperature to 551°F from the current value of 548.5°F.
- The maximum value of the long-term steady-state temperature in the RVI components as the result of gamma heating is 784.5°F, which will be at a subsurface location in the former plates of the core shroud near the mid-section of the core.
- A maximum neutron fluence after 60 years (52 effective full power years (EFPY)) at the inner surface of the core shroud of 6.586×10^{22} n/cm^2 (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 (52 EFPY) fluence will be 96.03 dpa. The EPU maximum fluence values for the 60-year EOL is presented in 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.

The NRC Staff's acceptance criteria for RVI and core support materials are based on GDC-1 and 10 CFR 50.55a for materials 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. Experience at operating plants as well as adherence to the primary coolant guidelines provided by the Electric Power Research Institute (EPRI), Pressurized-Water Reactor (PWR) Primary Water Chemistry Guidelines, indicates 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 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 PWR plants, as well as the EPRI guidelines, indicates that an initial limit of 3.5 ppm lithium with controlled boron concentrations to maintain a 6.9 to 7.4 pH has not produced undesirable material integrity issues in fuel cladding.

B. Stress Corrosion Cracking

Two degradation mechanisms that are operative in the austenitic SS 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 SS, requires the presence of halogens (e.g., chlorides) and dissolved oxygen. Both IGSCC and TGSCC in austenitic SS 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 have an effect on the potential for IGSCC or TGSCC in the austenitic SS in the RVI and core support components.

A high-strength, precipitation-hardening, austenitic SS (A-286) is used for 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 industry failures of A-286 fasteners in RVI applications. The available data indicated that the 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 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 IGSCC in reactor coolant. The evaluation also determined that the potential for IGSCC in the A-286 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 TSFs will be managed in accordance with UFSAR Section 18.1.4, RVI Inspection Program.

C. Irradiation Embrittlement

Exposure of austenitic SS 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 SS, 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 SS, radiation damage becomes significant at fluences above about 0.2 dpa, or approximately 1×10^{20} n/cm^2 (E>1MeV). At lower fluences, the radiation damage in austenitic SS is negligible. At fluences of 0.2 to approximately 10 dpa (6.7×10^{21} n/cm^2 (E>1MeV)), fracture toughness deceases 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 SS 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 become evident at lower fluences than for the wrought austenitic SS 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/cm^2 (E>1 MeV), however, recent laboratory data indicate that loss of toughness is negligible below fluences of approximately 1 dpa (6.7×10^{20} n/cm^2 (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 SS plates and austenitic SS weld metals in the core shroud. Other St. Lucie Unit 1 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,
- 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. 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 to 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, 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 significant tensile stresses. In the absence of high tensile stresses, or if the stresses are low, there will not be an impact 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)

IASCC is an age-related degradation mechanism in which materials, specifically austenitic SS, 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 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. (St. Lucie Unit 1 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/cm^2 (E>1MeV) to 1×10^{22} n/cm^2 (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/cm^2 (E>1MeV), the following RVI components are potentially susceptible to IASCC:

- Core shroud plates, ribs, former 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 SS wrought products (primarily plates) and weld metals. The CEA shroud bolts were fabricated from A-286 SS, 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 1 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 SS 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 SS 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 are at the center of the core where the former plate is twice the thickness of all other former 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 former plate locations, the former plates are thinner so the temperatures are significantly lower, making significant void swelling even less likely. In the core shroud panels (plates) near the former 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 RVI 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 core support columns. The temperature of the CEA shroud tubes at EPU conditions will be determined by the core outlet temperature (608.1°F) because the shroud tubes are sufficiently remote from the reactor core, such that gamma (internal) heating will be negligible. The temperature of the core support columns, which are below the active core and not significantly affected by gamma heating, will be at the core inlet temperature (551°F). Both applications use CASS with low molybdenum contents (<0.5%), which are less susceptible to thermal aging than the high molybdenum grades. The CEA shroud tubes were fabricated from centrifugal castings, which are not susceptible to thermal aging if the delta ferrite content does not exceed 20%. The castings for the core columns may have been cast by either static or centrifugal processes. 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 to 608.1°F) are relatively low and will not result in a significant loss of fracture toughness. The lower bound fracture toughness of the CASS components will not be affected, although Reference 3 suggests 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 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 doses of 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/cm^2 (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 core columns may be susceptible to this proposed synergistic effect because they experience neutron fluence in excess of the threshold and may have been statically cast. St. Lucie Unit 1 has aging management programs, as described in Chapter 18 of the UFSAR, which will address thermal aging of CASS components. The RVI 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 the 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 such 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 the 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/cm^2 (E>1MeV)). At St. Lucie Unit 1, the only bolting applications receiving significant neutron fluences are the A-286 SS CEA shroud bolt and solution annealed Type 316 SS cap screws which attach the snubber spacer blocks to the outside surface of the core support barrel (CSB). 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 snubber spacer bolts are either significantly above the reactor core (CEA shroud bolts) or below the core and on the outside of the CSB 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 on 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 temperatures and neutron fluences 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 the licensee 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 the reactor internal 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. NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, September 2003.

3. Pressurized Water Reactor Primary Water Chemistry Guidelines: Volume 2, Revision 5, EPRI, Palo Alto, CA: 2003. 1002884

4. NUREG-1801, Vol. 2, Rev. 1, Generic Aging Lessons Learned (GALL) Report Tabulation of Results, 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	Maximum Change In Steady-State Temperature after EPU, °F
2700 (current)	Core Inlet	548.5	-
2700 (current)	Core Outlet	594.0	-
2700 (current)	Vessel Outlet	594.0	-
3020 (EPU)	Core Inlet	551.0	2.5
3020 (EPU)	Core Outlet	608.2	14.2
3020 (EPU)	Vessel Outlet	606.0	12.0

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

Core Power Level (MWt)	n/cm^2, E>1 MeV	Displacements Per atom (dpa)
3020 (EPU)	6.586E+22[1]	9.603E+01[1]
1. Includes EPU conditions and 10% conservative factor after Cycle 26		

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 produced in the reactor. FPL's evaluation of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs.

The NRC's acceptance criteria for RCPB materials are based on:

- 10 CFR 50.55a 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-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 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 assure that, under specified conditions, it will behave in a nonbrittle 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.

Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in NRC 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the plant's licensing history with respect to GDCs

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the plant's design relative to the GDC is discussed in UFSAR Section 3.1.

The specific criteria related to the pressure retaining components and component supports' design are:

- 10 CFR 50.55a is described in UFSAR Section 5.2.3.1, "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 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.

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-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.

- 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 in accordance with the ASME Code Section III, and ANSI B 31.7. 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 maintain the stresses within applicable stress limits.

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

Means are provided to detect significant leakage from the RCPB with monitoring readouts and alarms in the control room as discussed in UFSAR Chapters 5 and 12.

- 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.

Carbon and low-alloy steel materials which form part of the RCPB meet the requirements of the ASME Code, Section III, paragraph N-330 at a temperature of +40°F. The actual nil-ductility transition temperature (NDTT) of the materials has been determined by drop weight tests in accordance with ASTM-E-208. For the reactor vessel, Charpy tests will be also performed and the results will be used to plot a Charpy transition curve. The NDTT as determined by drop weight test will be used to correlate the Charpy transition curve and establish nonirradiated base points for the surveillance program.

- 10 CFR 50, Appendix G, Fracture Toughness Requirements, are described in UFSAR Section 5.4.2, Heatup and Cooldown Limits.

The codes adhered to and component classifications for RCPB SSCs are listed in UFSAR Table 5.2-1 and conform to 10 CFR 50.55a.

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, IN 00-17, Bulletins 01-01, 02-01 and 02-02 are presented in LR Section 2.1.5.2. 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 bases 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 extended power uprate (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 5.2-4, Major Component Material Specifications; and Table 5.2-5, Materials Exposed to Primary Coolant.

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

- An assessment of the potential effect of the water chemistry changes on the (1) general corrosion (wastage) of the carbon steel components, and (2) stress corrosion cracking (SCC) of austenitic stainless steel components, and the management strategy of any issues there from.
- An assessment of the effect of the changes in the service temperature on (1) PWSCC of the Alloy 600/182/82 nickel base alloy components, and (2) thermal aging of cast austenitic stainless steel (CASS) materials in primary system components, and the management strategy of any issues there from.

These assessments are discussed in the following subsections.

2.1.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

EPU Service Conditions

Review of the EPU design parameters indicates that the RCS chemistry and 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 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 EFPD.
- For boron concentrations greater than 940 ppm, lithium concentration is maintained at 3.17 to 3.50 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.
- 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 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 12°F) and a maximum steady-state temperature at the reactor vessel inlet (cold-leg) of 551°F (maximum ΔT of 2.5°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 reactor coolant pressure boundary materials is discussed in the following paragraphs:

General Corrosion/Wastage of Carbon and Low Alloy Steel Components

After EPU implementation, the reactor coolant chemistry program will continue to be coordinated as noted above. Experience at operating plants as well as adherence to the primary coolant guidelines provided by the Electric Power Research Institute, EPRI pressurized-water reactor (PWR) Primary Water Chemistry Guidelines, indicates 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 (SGs), pressurizer, 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 X1.M10, Boric Acid Corrosion specified in

NUREG-1801, Revision 1, GALL Report (September 2005). This program utilizes systematic inspections, leakage evaluations, and corrective actions to insure 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 evaluation and found FPL's request for additional information responses acceptable since the program scope is consistent with the NUREG-1801 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 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).

After the discovery of leakage attributed to PWSCC in one hot leg instrument nozzle, FPL replaced all 19 Alloy 600 instrument and sampling nozzles in the hot legs 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 where carbon or low alloy steels are continuously exposed to primary coolant. There is not a mechanism for concentrating boric acid in the annular regions between the nozzles and hot leg piping. Thus, accelerated corrosion of the carbon steel will not occur but some minor corrosion may occur during plant operation and during shutdowns. WCAP-15973-P-A (Reference 2) 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 post-EPU conditions, including temperature, of the repaired nozzles. Therefore, the conclusions of the nozzle corrosion evaluation will continue to be valid after EPU, thereby indicating that the EPU will not affect the calculated lifetimes of the nozzle repairs.

WCAP-15973-P-A 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. Since the conditions evaluated bound the conditions after EPU, the conclusions of WCAP-15973-P-A remain valid after 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 involve the introduction of any of the chemical contributors to stress corrosion cracking. In the absence of these chemical contributors to IGSCC or TGSCC, the minor temperature increase resulting from EPU 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 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. 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 pressurizer and hot leg locations with more PWSCC resistant Alloy 690 and weld metals Alloy 52/52M/152 and austenitic stainless steels or by covering Alloy 182 dissimilar metal welds between nozzles and safe-ends with structural weld overlays of Alloys 52 or 52M. The remaining Alloy 600/82/182 components are managed by the Alloy 600 Management Program. The following components in the RCPB still contain Alloy 600/82/182:

- Hot-leg drain nozzle-to-safe-end weld.
- Nozzle-to-safe-end welds of the following cold-leg nozzles: letdown and drain, safety injection, charging inlet, spray, and reactor coolant pump (RCP) suction and discharge nozzles.
- 12 cold-leg instrument nozzles and the welds connecting the nozzles to the RCS piping and connecting the nozzles to austenitic stainless steel safe-ends.
- The cladding on the primary faces of the replacement SG tube sheets.

Alloy 690/52/52M/152 Components

Laboratory testing and industry experience since 1989 indicate that nickel-base Alloy 690 and Alloy 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 Alloy 82/182 welds with Alloy 52/52M/152 welds that are more PWSCC resistant.

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

- The control element drive mechanism (CEDM) nozzles and adaptors, in-core instrumentation (ICI) nozzles, and vent line of the reactor vessel closure head (RVCH) are Alloy 690. The weld metals attaching the nozzles and vent line to the RVCH and connecting the CEDM nozzles and adaptors and the ICI nozzles and adaptors are Alloy 52 or 152.
- The lower end fittings of the CEDM housings are Alloy 690. The welds between the martensitic stainless steel motor sections and upper and lower end fittings are Alloy 52M.

- The lower end fittings of the two reactor vessel level monitoring system housings are Alloy 690. The welds between the lower-end fittings and austenitic SS lower housings are Alloy 52 or 52M.
- The 120 heater sleeves and seven instrument nozzles in the pressurizer are Alloy 690 and were attached to the pressurizer with Alloy 52/152 welds.
- Nineteen hot leg instrument and sampling nozzles are Alloy 690 and the partial penetration welds between the nozzles and weld pads on the OD surface of the pipe sections are Alloy 52.
- Structural weld overlays on the surge nozzle safe-end weld and the two shutdown cooling nozzles safe-end welds (Alloy 52M).
- The SG heat transfer tubes are Alloy 690.

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 the form

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

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 (°F + 459.7°)

The above equation indicates that the maximum temperature after EPU is implemented in the hot legs (606°F) will decrease the remaining lifetimes to PWSCC initiation of Alloy 600/82/182 containing components by approximately 38 percent. The only Alloy 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 each refueling outage as part of the Alloy 600 inspection program and plans to replace or mitigate this weld. The remaining Alloy 600/82/182 components are managed by the Alloy 600 management program.

The Alloy 82 SG tubesheet clad is exposed to hot leg temperatures. If through cladding cracks develop as the result of PWSCC, the tubesheet base material (low alloy steel SA-508 Class 3) will be exposed to primary coolant. Minor corrosion of the forging could result, but the overall corrosion rate during operating and shutdown conditions will be low; therefore, only minor tubesheet corrosion will occur over the remaining lifetime of the SGs. WCAP-15973-P-A (Reference 2) indicates that an increase in temperature of the primary coolant will not result in an increase in corrosion rate of low-alloy steel. Thus, the temperature increase of the reactor coolant resulting from implementation of the EPU will not result in an increase in the corrosion rate of the tubesheet material if the cladding should crack.

Alloy 600 Management Program

FPL has a comprehensive Alloy 600 management plan (Reference 3) to address the PWSCC issue. The program includes following of the industry experience, identifying and ranking Alloy 600/182/82 locations, developing and maintaining inspection plans, and development of mitigation/repair/replacement strategies for the remaining Alloy 600/182/82 components and welds.

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

FPL has addressed PWSCC of Alloy 600 by either replacing most of the Alloy 600/82/182 in components most susceptible to PWSCC (pressurizer, hot leg piping, RVCH, SGs) 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 data base 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 SGs tubes, pressurizer instrument nozzles and heater sleeves, RVCH 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 metals Alloy 52/52M/152 have been in-service in PWR RCPB components for approximately 15 years under the same conditions without any reports 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 metals Alloy 52/52M/152.

The RVCH has Alloy 690 CEDM nozzles, ICI nozzles and vent line and Alloy 52 or 152 welds.

To insure safe management of the potential for PWSCC of Alloy 690 nozzles in RVCHs, the NRC has mandated the following inspection plan for replacement RVCHs:

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(g)(6)(ii)(D)(2) through (6). Code Case N-729-1 stipulates the following requirements for the inspection of replacement RVCHs with nozzles and partial penetration welds of PWSCC resistant materials (Alloy 690 with Alloy 52/152 welds):

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

  A bare metal visual examination of the entire outer surface of the head, including essentially 100% 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% of the area in the region of the nozzles and the head surface uphill and downhill of the obstructions.

- An inspection of the 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% 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 the 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.

The RVCH was replaced in 2005. FPL plans to conduct an initial bare metal visual inspection in 2010.

Thermal Aging (Embrittlement) of Cast Austenitic Stainless Steels

Thermal aging (embrittlement) is a degradation mechanism occurring in cast austenitic SS (CASS) that manifests itself as increases in hardness and yield strength and reductions in ductility and fracture toughness. CASS (SA-351 Grade CF8M) is present in the hot leg piping in the safe-ends of the surge, drain, 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 RCP casing and covers, the safe-ends of pipe sections that connect to the RCP suction and discharge nozzles and the safe-ends of safety injection, spray, charging, let down and drain 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. 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 does not require screening for susceptibility to thermal embrittlement because 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 and 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 for which CMTRs were available were centrifugally cast, had lower bound fracture toughness values greater than the 1450 in-lbs/in^2 criterion of NUREG-1801 and most heats had delta ferrite contents of less than 20%, indicating that they are not susceptible to thermal aging. However, CMTRs were not available for several heats of CASS used in pipe applications. In the absence of data on chemical composition, casting method and delta ferrite content, these heats cannot be shown to satisfy the screening criteria and may be susceptible to thermal aging. CASS piping without available CMTR data will be managed by the Thermal Aging Embrittlement of CASS Program.

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. Since some of the CASS components screen as potentially susceptible (because of insufficient information) before the EPU, they will continue to require aging management in accordance with NUREG-1801. Temperatures increases resulting from the EPU will not impact existing 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 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.

2.1.5.2.5 Results

The assessment of the potential materials degradation issues associated with the proposed extended power uprate resulted in the following conclusions:

- There are not any 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 changes associated with the EPU. 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. 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 an earlier analysis bound the conditions expected after EPU implementation. Therefore, additional material degradation of these areas as the 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 the result of the EPU.
- The increase in the primary coolant temperature will increase the potential for PWSCC of the Alloy 600/182/82 remaining in the RCPB components. However, most of the

Alloy 600/182/82 at the most susceptible high temperature locations has been replaced or repaired/mitigated by more PWSCC resistant materials. The remaining Alloy 600/82/182 pressure boundary components are monitored in the Alloy 600 management program to maintain plant safety, maintain the integrity of the RCPB and to minimize the affect of PWSCC. As a result, the potential for future PWSCC of the remaining Alloy 600/182/82 is managed.

- Alloy 690/152/52 is present in the RVCH, the CEDM and reactor vessel level monitoring system housings, the pressurizer, hot leg instrument and sampling nozzles, and in structural weld overlays. The risk for PWSCC of the Alloy 690/152/52 is minimal based on industry experience with these materials. FPL will continue to monitor the industry program to manage the Alloy 690/152/52 issue.
- The small increase in temperature resulting from the EPU will not result in lower fracture toughness in RCPB component fabricated from cast austenitic stainless steel. The NRC review 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) concluded that FPL's Generic Aging Lessons Learned (GALL) process identified in the License Renewal Application (LRA) is consistent with the GALL Report (NUREG-1801) 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 assessment showed that no new materials degradation issues will result from the proposed power uprating. 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 accepted by the NRC in the SER.

2.1.5.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the susceptibility of reactor coolant pressure boundary 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 reactor coolant pressure boundary materials. FPL further concludes that it has demonstrated that the reactor coolant pressure boundary 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. 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.

2. Westinghouse Report WCAP-15973-P-A, Rev. 0, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs, March 9, 2005.

3. Florida Power & Light Document ENG-CSI-A600, Rev. 1, Alloy 600 Management Program for St. Lucie Units 1 and 2 Turkey Point Units 3 and 4, November 29, 2007.

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

Core Power Level (MWt)	Location	Temperature, Maximum (°F)	Maximum Change in Steady-State Temperature after EPU (°F)
2700 (current)	RV Outlet	594	-
2700 (current)	RV Inlet	548.5	-
3020	RV Outlet	606.0	12
3020	RV Inlet	551.0	2.5

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.

FPL's 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 over-pressurizations, fires, flooding, missiles, and failures of structures, systems and components (SSCs) in close proximity to the piping);
- deterministic fracture mechanics and leak detection methods.

The NRC's acceptance criteria for LBB are based on

- GDC-4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis.

Specific review criteria are contained in the Standard Review Plan (SRP) Section 3.6.3, Revision 1, and other guidance provided in Matrix 1 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for LBB are 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 below 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 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 LBB methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects associated with circumferential (guillotine) and longitudinal (slot) breaks do not have to be considered. A technical evaluation was performed to demonstrate that the probability of likelihood of such breaks occurring is sufficiently low that they need not be a design basis (see Reference 1).

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. Local missile barriers are 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 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 Class I seismic pipe which causes a 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.

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 the UFSAR Sections 3.5, 3.6, 3.7.5 and 3.11 for details.

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 include the following statement: "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 demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping". 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 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 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 bases described in the UFSAR, LBB was evaluated for St. Lucie Unit 1 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 NRC Generic Letter (GL) 84-04. Westinghouse submitted the RCS asymmetric loads analysis results (Reference 2) to the NRC for their review. The Reference 2 report applied to the St. Lucie Unit 1 as well as to 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 confirmed that the asymmetric blowdown loads resulting from double-ended pipe breaks in primary loop piping need not be considered as a design basis at St. Lucie Unit 1.

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 continues to be valid following implementation of the EPU, and that the primary loop piping, for which St. Lucie Unit 1 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.
- Demonstrate that fatigue crack growth is negligible.

These objectives were met in the current LBB evaluation by addressing the changes due to 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

Input Parameters

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, normal operating temperature (NOT), and 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 of this Licensing Report.

Assumptions

There are no assumptions pertaining to LR Section 2.1.6.

Acceptance Criteria

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 flaw size
- Margin of $\sqrt{2}$ on loads for leakage flaw 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 for the St. Lucie Unit 1 License Renewal Program. The evaluation consisted of a comparison of the input parameters previously documented in Reference 1 and approved by the NRC in Reference 3 versus 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 operating pressure did not change due to EPU,
- the postulated leakage crack length was calculated in Reference 1 on the basis of “pressure only” loads and therefore also did not change,
- The safe shutdown earthquake (SSE) loads on the primary loop piping are unchanged 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 specified for St. Lucie Unit 1 and used in Reference 1. The evaluation determined that the updated piping loads were enveloped by the piping loads previously evaluated in Reference 1 to demonstrate acceptable margins for LBB.

The EPU LBB evaluation is based on the original 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 employed. The results of the evaluation demonstrated that 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 should not be 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 1 LBB applications, these limitations are addressed in Reference 1 for primary loop piping and approved by the NRC in Reference 3. EPU conditions do not effect the 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 flaw and the leakage detection capability as described in UFSAR Section 5.2.4.
- Flaw Size – A margin of 2.0 or more exists between the critical flaw size and the leakage flaw size.
- 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 primary loop piping remain unchanged for the EPU conditions.

It is therefore concluded that the LBB acceptance criteria continue to be satisfied for the 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 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 1 and determined that (1) there are no changes in primary system pressure due to 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 1.

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. NPSD-110, Revision 000, Reactor Coolant System Asymmetric Loads, Final Report, June 30, 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 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 NRC 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 SRP, Section 6.1.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0 for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The application of protective coating systems inside the containment (and elsewhere in the plant) pre-dated RG 1.54, Rev. 0, and ANSI Standard N101.4.

As stated in UFSAR Section 3.8.3.6.1, 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 6.3.6 provides the summary of the response to NRC Generic Letter (GL) 98-04, regarding potential degradation of emergency core cooling system (ECCS) and containment spray (CS) system due to protective coatings failure and foreign material accumulation in containment recirculation sumps after a LOCA. FPL's response to GL 98-04 is documented in a letter from J. A. Stall (FPL), *Generic Letter 98-04 Initial Response,* to NRC Document Control Desk; dated November 4, 1998 as summarized below. The NRC closed this issue for St. Lucie Unit 1 via letter from K. N. Jabbour, (NRC), *Completion of Licensing Action for Generic Letter 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,* to T. F. Plunkett (FPL) dated December 9, 1999.

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;
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 bases described in the UFSAR, the protective coating system was evaluated for St. Lucie Unit 1 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 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 sodium hydroxide (NaOH) injection into the containment spray 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.

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	265.57°F
2.8–23.9 Hrs	219°F	~215°F
Maximum Pressure at LOCA conditions		
Pressure	54 psig	42.77 psig
Integrated Radiation Dose at LOCA conditions		
Radiation Dose	3×10^8 Rads	2.25×10^7 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.

FPL has reviewed 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 NUREG-1344, NRC Generic Letter (GL) 89-08, and the guidelines in Electric Power Research Institute (EPRI) Report NSAC-202L-R2 & R3 “Recommendations for an Effective Flow-Accelerated Corrosion Program” dated April 1999 and August 2007 respectively. The FAC program predicts loss of material using the CHECWORKS™ computer code, as well as visual inspection and volumetric examination of the affected components.

The NRC’s acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

St. Lucie Unit 1 Current Licensing Basis

The FAC program has been developed in response to NRC Bulletin 87-01, Thinning Pipe Walls in Nuclear Power Plants, GL 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning, and the guidelines in EPRI Report NSAC-202L-R2 & R3. The CHECWORKS™ SFA computer code is utilized as recommended by NSAC-202L-R2 & 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 & 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.

The review requirements associated with “Note 4” as described in Matrix 1 of Section 2.1 of RS-001 are addressed in LR Section 2.1.8.2.

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 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
- 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 mechanisms (i.e., cavitations, 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 & R3 were utilized to determine the susceptible systems and exclusion criteria. 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, plant systems are considered susceptible to FAC unless excluded by the following criteria:

- Piping material – stainless steel, stainless clad materials (a low-alloy steel with normal chromium content ≥ 1¼%)
- 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
- System usage – use < 2% or > 200°F with usage < 2% of the operating time except for conditions of two-phase flow which do 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
- 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. Wear rates of piping components are obtained using the wear calculation feature of CHECWORKS™ SFA.

The FAC computer program utilizes CHECWORKS™ SFA for determination of minimum wall thickness. Piping component structural calculations, where required to satisfy code requirements, shall be performed by site engineering.

Certain systems and pipe segments have usage and flow rates that cannot be accurately quantified because demand and operating conditions vary greatly or are controlled by a remote level, pressure, or temperature signal. These systems cannot be effectively modeled using CHECWORKS™ SFA and are categorized as Susceptible-Non-Modeled systems.

For determination of wear rates in Susceptible-Non-Modeled lines, ultrasonic testing (UT) or radiography techniques (RT) inspections are performed at selected locations, usually immediately downstream of flow orifices, steam traps, control valves, etc. The five methods commonly used for determining the wear of piping components from inspection data are: (1) Band Method, (2) Averaged Band Method, (3) Area Method, (4) Moving Blanket Method, and

(5) Point-to-Point Method. Although methods (1) through (4) use different approaches, the total wear is the difference between an initial/baseline thickness and the minimum measured thickness. This value is divided by the 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 small bore components and may be used on large bore components that are 8 inches in diameter or less and Schedule 40. Computed radiography is not used where wear rate trending is required.

For determination of wear rates in large bore Susceptible-Non-Modeled piping and components in the FAC program, ultrasonic testing measurements are taken at selected locations. The FPL FAC engineer then determines the wear rate and predicts the wall thickness at the 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 ¾ inches up to and including 2 inches) that are included in the FAC program
- Lines based on industry and plant specific operating experience

The FAC outage inspection plan also show 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. and forwarding this information to the FAC engineer 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
- Other reviews

CHECWORKS™ SFA Analysis of Large Bore Systems

Once a system is adequately represented in CHECWORKS™, 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 1, the component remaining life is the time to achieve the minimum wall thickness required and is denoted by "t_{min}" or "t_{crit}".

Susceptible-Non-Modeled CHECWORKS™ SFA 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 engineer 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
- Components that are adjacent to components that have been replaced in the past

Susceptible-Non-Modeled Small Bore Systems

Historical inspection and replacement data is reviewed to determine prior inspection coverage on each component. The FAC engineer 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 1 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,
- 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 engineer.

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 preceding 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 engineer. 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 for St. Lucie Unit 1 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. LR 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, LR 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 LR 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 code. This is normally the larger of the code required minimum wall thickness for hoop stress, or 0.150 inch. 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 & 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% 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 LR Table 2.1.8-3 will govern replacement even though the code minimum thickness maybe 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 & 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 1 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 2008 SL-1-22 outage, feedwater heater 4B vent to condenser was replaced with FAC-resistant material.

During the 2007 SL-1-21 outage, lines associated with steam traps I-ST-08-1, ST-08-2 and ST-08-3 were replaced with FAC-resistant material.

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 NUREG-1344, GL 89-08, and the guidelines in EPRI Report NSAC-202L-R2 & 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 the 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 Reheaters (MSRs) and Feedwater Heaters at EPU Conditions.
5. Update of the CHECWORKS™ SFA Model for EPU Conditions.
6. FAC Program Requirements, Methods, and Criteria.
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

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

  - Flow through main steam piping from the main steam isolation valve (MSIV) to the MS common header exceeds the industry guidelines by approximately 12%.
  - Flow through main steam piping from the steam generator (SG) outlet to the MSIV exceeds the industry guidelines by approximately 14%.

  The main steam 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 4A/B exceeds industry guidelines by approximately 3%;
  - flow 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 28%; under EPU conditions the velocity exceeds industry guidelines by approximately 40%;
  - flow through the cold reheat piping from the LP heater 4 A/B steam supply connection to the MSRs currently exceeds industry guidelines by approximately 3.6%; under EPU conditions the velocity exceeds industry guidelines by approximately 10%.

The CHECWORKS™ 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 of 8–15 fps, with two exceptions, as follows:

  - The 8-inch main feedwater pump recirculation lines require replacement to meet industry guidelines. Following the replacement, FAC monitoring will continue in accordance with the FAC program.
  - The low pressure feedwater heater number 3 inlet header exceeds the industry guidelines by approximately 3% at EPU operating conditions. The operation of this line is considered acceptable for EPU operations and will continue to be monitored by the FAC program.

  The CHECWORKS™ 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 guideline by 7.5% and the EPU flow velocity increases that by an additional 2.5%. The flow velocity for feedwater heater 2 to feedwater heater 1 increases from below industry guidelines to approximately 380% above industry guidelines. A modification will be performed to lower the elevation of the level control valves (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 guideline, and therefore, the EPU flow velocities will also exceed the industry guideline. 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 heater, 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™ 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 SGs 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 may 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 with 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 experiencing 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 velocities have 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 the 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

- Due to modifications to the feedwater pumps to meet the increased EPU flow requirements the 8-inch main feedwater pump recirculation lines will require replacement to meet industry guidelines.
- A modification will be implemented to reduce flow velocities in the lines 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 -1-38	24C37-E-1-6	Elbow	24"–0.688" Sch 40	1.458	1.896
CONDENSATE	CD: HD TIE IN-HTR 4A	24C37-P-4-11	Pipe	24"–0.688" Sch 40	1.588	1.824
CONDENSATE	CD: HTR 1A,B-2A,B PSL-1-34	20C26-2-E-5-9	Elbow	20"–.594" Sch 40	1.06	1.03
CONDENSATE	CD: HTR 2B-3B PSL-1-35,36	20C31-3-P-2-7	Pipe	20"–.594" Sch 40	0.883	0.840
CONDENSATE	CD: HTR 3A-DRNCLRA PSL-1-37,	20C35-P-9-20	Pipe	20"–.594" Sch 40	1.481	1.547
CONDENSATE	CD: HTR 4A-BF PUMP A 1-40	24C49-E-7-19	Elbow	24"–.688" Sch 40	1.745	1.859
EXTRACTION STEAM	ES: XUES TO FWH 4B 1-20,	20ES4-P-6-13	Pipe	20"–.375" Sch 20	0.039	0.038
EXTRACTION STEAM	ES: MSR TIEIN TO FWH 5B -1-18	12ES2-E-15-38	Elbow	12"–.375" Std	0.259	0.029
FEEDWATER	BF: HTR 5B TO SEISMIC -1-43,45	20BF9-1-R-1-2 (D/S)	Reducer	20"–1.500" Sch 120	2.167	2.467
FEEDWATER	BF: PUMP A to HTR 5A -1-41,42,	20BF1-3-E-6-19	Elbow	20"–1.500" Sch 120	6.15	6.574
HEATER DRAIN	HD: DRNCLR A TO PUMP A -1-24	16HD34-3-E-5-13	Elbow	16"–.375"	1.128	1.164
HEATER DRAIN	HD: PMPB TO CD TIE 1-25,27,28	14HD40A-E-7-22	Elbow	14"–.438" Sch 40	1.388	1.394
HEATER DRAIN	HD: FWH 1A TO CONDENSER -1-33	10HD53-P-3-9	Pipe	10.75"–.365" Sch 40	0.443	0.488
HEATER DRAIN	HD: FWH 2A TO FWH 1A -1-22	8HD60-1-P-2-6	Pipe	8.625"–.322" Sch 40	0.762	0.854
HEATER DRAIN	HD: FWH 3A TO FWH 2A -1-31,	6HD47-E-1-3	Elbow	6.625"–.280 Sch 40	1.585	1.858
HEATER DRAIN	HD: FWH 4A TO DRNCLR 1A -1-23	30HD29-4-P-5-10	Pipe	30"–.375"	0.289	0.316
HEATER DRAIN	HD: FWH 5B TO FWH 4B -1-22	10HD17-1-E-2-5	Elbow	10.750"–.365" Sch 40	1.700	1.832
EXTRACTION STEAM	ES: HP A TO MSR TIE IN -1-17	12ES1-1-E-1-2	Elbow	10.750"–.375" Sch 40	2.307	2.304
EXTRACTION STEAM	ES: LPES TO FWH 3A,B -1-29,30	24ES5-3-P-6-12	Pipe	24"–.375" Sch 20	1.655	4.280
MAIN STEAM	MS: CLBK TO TURB CON1,3 -1-2	3A3-38MS15-2-R-3-63	Reducer	38"–1.25" Sch USR	0.082	0.245
MAIN STEAM	MS: XU-HPT to MSR 1A PSL-1-3	4A-HP-MSR1A-P-9-18	Pipe	36"–.750" Sch 40	9.211	8.883
MAIN STEAM	MS: TO MSR 1A RHTR -1-9,10	8MS19-P-6-12	Pipe	8.625"–.322" Sch 40	1.405	1.86
HEATER DRAIN	HR: MSR C RHTR TO FWH5A -1-14	6HD14-13P13-30	Pipe	6.625"–.280" Sch 40	0.687	0.747
HEATER DRAIN	HR: MSRCD SHL TO FWH4A -1-5	12HD11-P6-13	Pipe	12.75"–.406" Sch 40	0.666	0.791

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 SL1-25 @ EPU Wear Rate (months)	Predicted Thickness at Current Wear Rate at the end of Cycle 24 (inches)	NDE (UT or RT) Measured Thickness (inches)(2)
CD: DRCLRA-HTRDR TIE IN -1-38	24C37-E-1-6	24"–0.688" wall	1.458	0.978	764	0.711	0.724@ 177947 hrs.
CD: HD TIE IN-HTR 4A	24C37-P-4-11	24"–0.688" Sch 40	1.588	0.978	282	0.633	0.650 @ 128590 hrs.
CD: HTR 1A,B-2A,B PSL-1-34	20C26-2-E-5-9	20"–.594" Sch 40	1.06	0.978	282	0.516	No NDE
CD: HTR 2B-3B PSL-1-35,36	20C31-3-P-2-7	20"–.594" Sch 40	0.883	0.978	536	0.529	No NDE
CD: HTR 3A-DRNCLRA PSL-1-37,	20C35-P-9-20	20"–.594" Sch 40	1.481	0.978	445	0.55	0.565 @ 165757 hrs.
CD: HTR 4A-BF PUMP A 1-40	24C49-E-7-19	24"–.688" Sch 40	1.745	0.978	410	0.654	0.683@ 128590 hrs.
ES: XUES TO FWH 4B 1-20,	20ES4-P-6-13	20"–.375" Sch 20	0.039	1.00 (1)	55013	0.374	No NDE
ES: MSR TIEIN TO FWH 5B -1-18	12ES2-E-15-38	12"–.375" Std	0.259	1.00 (1)	78157	0.369	No NDE
BF: HTR 5B TO SEISMIC -1-43,45	20BF9-1-R-1-2 (D/S)	20"–1.500" Sch 120	2.167	2.441	692	1.336	No NDE
BF: PUMP A to HTR 5A -1-41,42,	20BF1-3-E-6-19	20"–1.500" Sch 120	6.15	2.441	985	1.738	1.763@ 213815 hrs.
HD: DRNCLR A TO PUMP A -1-24	16HD34-3-E-5-13	16"–.375"	1.128	0.670	1298	0.286	No NDE
HD: PMPB TO CD TIE 1-25,27,28	14HD40A-E-7-22	14"–.438" Sch 40	1.388	0.670	297	0.402	0.415@ 177947 hrs.
HD: FWH 1A TO CONDENSER -1-33	10HD53-P-3-9	10.75"–.365" Sch 40	0.443	1.238	7782	0.332	No NDE

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 SL1-25 @ EPU Wear Rate (months)	Predicted Thickness at Current Wear Rate at the end of Cycle 24 (inches)	NDE (UT or RT) Measured Thickness (inches)(2)
HD: FWH 2A TO FWH 1A -1-22	8HD60-1-P-2-6	8.625"–.322" Sch 40	0.762	1.238	3519	0.266	No NDE
HD: FWH 3A TO FWH 2A -1-31,	6HD47-E-1-3	6.625"–.280 Sch 40	1.371	1.238	931	0.163	0.280@ 225812 hrs.
HD: FWH 4A TO DRNCLR 1A -1-23	30HD29-4-P-5-10	30"–.375"	0.289	1.159	2864	0.352	No NDE
HD: FWH 5B TO FWH 4B -1-22	10HD17-1-E-2-5	10.750"–.365" Sch 40	1.700	1.159	520	0.232	No NDE
ES: HP A TO MSR TIE IN -1-17	12ES1-1-E-1-2	12.75"–.375" Sch 40	2.307	0.290	862	0.347	0.380@ 177947 hrs.
ES: LPES TO FWH 3A,B -1-29,30	24ES5-3-P-6-12	24"–.375" Sch 20	1.655	3.754	643	0.286	0.375@ 177947 hrs.
MS: CLBK TO TURB CON1,3 -1-2	3A3-38MS15-2-R-3-63	38"–1.25" Sch USR	0.082	1.00 (1)	1494	1.247	No NDE
MS: XU-HPT to MSR 1A PSL-1-3	4A-HP-MSR1A-P-9-18	36"–.750" Sch 40	9.211	1.00 (1)	89	0.353	No NDE
MS: TO MSR 1A RHTR -1-9,10	8MS19-P-6-12	8.625"–.322" Sch 40	1.405	6.997	110	0.295	No NDE
HR: MSR C RHTR TO FWH5A -1-14	6HD14-13P13-30	6.625"–.280" Sch 40	0.687	0.983	288	0.231	No NDE
HR: MSRCD SHL TO FWH4A -1-5	12HD11-P6-13	12.75"–.406" Sch 40	0.666	0.688	3377	0.349	0.379@ 96883 hrs.

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 & 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, NEI 97-06 for structural and leakage performance criteria.

St. Lucie Unit 1 Current Licensing Basis

UFSAR Section 5.2.5, 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 shall be 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.l. 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 St. Lucie Unit 1 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 1998 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 lattice bars which reduce corrosion at the tube support intersections. 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 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.l, 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 603.2°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 would have an impact on allowable degradation, i.e., condition monitoring and operational limits. The current differential pressure is 1365 psi, which will increase to 1410 psi with the EPU. The calorimetric measurement-based calculations used plant measured calorimetric data from cycle 21 to determine the change in T_{hot}. For an average T_{hot} of 593.6°F for cycle 21, the expected best estimate difference is an increase of 9.6°F (593.6°F to 603.2°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 21, are limited to wear at tube supports and wear due to foreign objects. The impact of EPU conditions on past observed wear rates was assessed in LR Section 2.2.2.5.2.5, Flow-induced Tube Vibration and Wear. The results of the assessment demonstrated that over a 40-year operating life, the EPU did not significantly increase the maximum calculated tube wear as compared to the benchmark case prior to EPU. Furthermore, the end-of-cycle 21 operational assessment has determined that the maximum calculated allowable operating interval exceeds the planned inspection interval by at least a factor of 1.7. Therefore, there is significant margin in the current inspection interval schedule that would compensate for unexpected changes in tube wear rates after EPU is implemented.

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 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.

2.1.9.2.4 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 fan bars in the u-bend region and at horizontal lattice supports in straight sections. The cumulative plugging fraction for both SGs is very low for all causes: only 0.16% in SG 1A and 0.01% in SG 1B. The inspection-to-inspection anti-vibration bar wear rates observed in the replacement SGs have diminished over time. The results of the tube vibration assessment demonstrated that over a 40-year operating life, the EPU did not significantly increase the maximum calculated tube wear as compared to the benchmark case prior to EPU. The end-of-cycle 21 operational assessment confirms there are significant margins in the inspection interval beyond the present evaluation that would compensate for an unexpected change in wear rates after EPU is implemented.

Cumulatively, there are 29 (0.17%) tubes with identified tube support wear. 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. Only one tube has been plugged due to foreign object wear that was detected during the end of cycle 21 inspections in SG 1B.

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. All known foreign objects have been retrieved. Based on the end of cycle 21 inspections, no actively tracked foreign objects remain in the SGs.

Corrosion Degradation - For the expected increase in T_{hot} (T_{hot} increasing from 593.6°F to 603.2°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.

SG tubing has not experienced any corrosion-related degradation. For the expected increase in T_{hot} (T_{hot} increasing from 593.6°F to 603.2°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 1 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 pressure differential across the tube wall used in the current assessment is 1417 psi, which bounds the projected EPU value of 1410 psi. 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.

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. FPL's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including anticipated operational occurrences (main condenser inleakage and primary-to-secondary leakage).

The NRC's acceptance criteria for the SGBS are based on:

- 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.

Specific review criteria are contained in SRP Section 10.4.8.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for the SGBS is 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 in accordance with the ASME Code Section III, and ANSI B 31.7. 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 maintain the stresses within applicable stress limits.

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

Means are provided to detect significant leakage from the RCPB with monitoring readouts and alarms in the control room as discussed in Chapters 5 and 12.

The RCPB has provisions for in-service inspection as described in Section 5.2.5, to ensure continuance of the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with ASTM-E-185 is provided as discussed in Chapter 5.

UFSAR Section 10.4.7 describes the SGBS. The SGBS is utilized to maintain the total dissolved solids content of SG secondary side coolant within normal operating limits.

The SGBS design bases are:

a. to control SG secondary side coolant chemistry within normal operating limits;
b. to ensure that any activity levels associated with the blowdown effluent when combined with other liquid effluents will comply with limitations governing these releases as set forth in the Offsite Dose Calculation Manual; and
c. to provide blowdown system containment isolation capability in accordance with GDC-57.

The SGBS is required to support normal operations. It is not required to achieve a safe shutdown, or mitigate the consequences of an accident. Although based on the guidance set forth in Regulatory Guides 1.26 and 1.29 it is a Quality Group D system that need not be seismically designed, the portion of the piping and valves at the containment penetrations are seismic to insure containment integrity following a containment isolation signal. Since the SGBS is not safety related, it is housed in a structure designed to standards appropriate for non-safety-related structures.

SG secondary side water chemistry control is accomplished by:

a. Control of feedwater purity to limit the amount of impurities introduced into the steam generator.
b. Minimize feedwater oxygen content prior to entry into SGs.
c. Chemical addition to establish and maintain an environment which minimizes system corrosion.
d. Continuous blowdown to reduce concentration effects within the SG.
e. Condensate polisher filter demineralizer 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 cooling water leakage, air inleakage and subsequent corrosion product generation). Solids are also excluded by injecting only volatile chemicals to establish conditions which reduce corrosion and, therefore, reduce the transport of corrosion products into the steam generator.

UFSAR Section 9.3.2.2.1.e, SGBS Samples, states that the samples taken from the SGBS are used to continuously monitor the SG conductivity, pH, and radiation levels. A low pressure, low temperature sample can also be taken at the steam generator blowdown sampling sink and at the cold chemistry lab in order to monitor SG chemistry.

In addition to the licensing bases described in the UFSAR, the SGBS was evaluated for St. Lucie Unit 1 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 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 10.4.7. Containment isolation is discussed in UFSAR Section 6.2.4. The steam and power conversion system is discussed in UFSAR Section 10.1 through 10.4. The secondary system 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 19,799 lb/hr and 118,787 lb/hr from above the SG tube sheet from two 2-inch blowdown nozzles that are piped into a single blowdown header per SG. This continuous blowdown prevents the concentration of soluble and insoluble impurities in the SGs, thus preventing or minimizing the degradation of the RCPB SG tubes from the secondary side.

The blowdown pipe lines from each SG pass through the containment penetrations and containment isolation valves to either a blowdown tank or to the SG blowdown treatment facility where the blowdown is cooled, filtered, purified by ion exchange and sent to monitoring storage tanks prior to recycling back to the condenser or to the discharge canal. The blowdown is cooled using a closed cycle cooling system to 139°F which is cooled by the open cycle cooling system. The intake cooling water system provides the cooling for the open cycle heat exchangers.

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 SG vendor confirmed that the EPU will have a negligible impact on SG water chemistry and accordingly, the blowdown requirements required to maintain water chemistry are unchanged at EPU.

The SGBS radiation monitors prevent the release of radioactivity to the discharge canal. Sampling provides verification of maintaining the total dissolved solids and pH within the required range for protecting the steam generator 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 evaluations were performed for an analyzed power of 3050 megawatts thermal (MWt) including pump heat.

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 that the blowdown requirements, including continuous and peak flow rates, are not impacted by EPU. Therefore, the supporting systems, such as the radiation monitoring system, SG blowdown treatment facility, demineralization system, air blower system, waste management system and spent resin system, are expected to perform satisfactorily under EPU operating conditions.

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 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 SG vendor confirmed that the EPU will have a negligible impact on SG water chemistry. The vendor also confirmed that the blowdown flow requirements are not impacted by EPU. Therefore, no changes to the SGBS design flow rates or operating modes are needed as a result of the EPU.

Since the blowdown flow rate does not change for EPU, the operation of the flow control valves and their control circuits does not change.

The pressure and temperature in the secondary side of the SGs is slightly reduced (2.5 psi and 0.4°F) for EPU operation. The existing design pressure and temperature of the SG blowdown piping (985 psig and 550°F) remain bounded for EPU since the conditions these values are based upon do not change at EPU The SGBS piping, including the pumps, valves, tanks, vessels and heat exchangers is unchanged by the EPU operation.

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 an accident. The SG vendor confirmed that blowdown system requirements are not changing at EPU and, therefore, these valves will continue to meet their containment isolation design function.

The effects of the EPU on the SGBS system have been evaluated with the conclusion that the SGBS continue to meet the current license basis requirements with respect to the RCPB. 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.

The ability of the SGBS system to remove particulate and dissolved impurities from the steam generator secondary side during normal operation, including operational occurrences, will not be affected. No modifications to the SGBS are required for EPU.

UFSAR Section 6.2.4.4, Containment Isolation System, discusses the containment isolation function of the SGBS 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 18.2.9, 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 blowdown systems, and is based on industry guidelines and experience. The SGBS piping will continue to be monitored under the FAC Program. (LR Section 2.1.8, Flow-Accelerated Corrosion).

UFSAR Section 18.2.5, 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 internal environment of the systems and components. 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 the 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.

FPL reviewed the safety-related functional performance characteristics of the CVCS components.

The NRC's acceptance criteria are based on

- 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;
- GDC-29, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

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

The impact of the EPU on the boron recovery system is provided in LR Section 2.5.6.2, Liquid Waste Management Systems.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the CVCS 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.

RCS components are designed in accordance with the ASME Code Section III, and ANSI B 31.7. Quality control, inspection, and testing as required by this standard, as well as reactor pressure-temperature limitations, 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 stress limits.

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

Means are provided to detect significant leakage from the RCPB with monitoring readouts and alarms in the control room as discussed in UFSAR Chapters 5 and 12.

The RCPB has provisions for in-service inspection as described in UFSAR Section 5.2.5, to ensure the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with ASTM-E-185 is provided as discussed in UFSAR Chapter 5.

- 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 ANS-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 anticipated operational occurrences.

UFSAR Section 9.3.4 describes the design bases of the CVCS. In part, it states that the CVCS is designed to maintain the required volume of water as well as the chemistry and purity of the reactor coolant. It accommodates the RCS water inventory change for a full-to-zero power decrease with no makeup system operation and injects concentrated boric acid into the RCS upon receipt of a safety injection actuation signal (SIAS). It controls the boron concentration in the RCS and provides auxiliary pressurizer spray for pressure control. It is also used to collect the controlled bleedoff from the reactor coolant pump seals. The CVCS can withstand the expected transients discussed in UFSAR Table 9.3-9 without any adverse effects. It provides a means for filling and maintaining the boron concentration of the safety injection tanks (SIT).

Also, as described in UFSAR Section 6.2.4, the CVCS supports containment isolation system functions of limiting the release of potentially radioactive materials to the environment through CVCS piping sections which penetrate the containment.

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 pumps, and
- Emergency power supply from operable diesel generators.

In addition to the licensing bases described in the UFSAR, the CVCS was evaluated for St. Lucie Unit 1 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 chemistry of the letdown flow may be altered by passing the flow through ion exchangers that remove ionic impurities. A filter removes solids, and the gases dissolved in the coolant are removed, added, or maintained in the VCT, as applicable. The boric acid concentration in the coolant is changed by the reactor makeup portion of the CVCS as required for reactivity control. The boric acid and charging portions of the CVCS perform safety-related functions for injecting boric acid into the RCS following a SIAS during accident conditions or for safe shutdown of the plant. Excess coolant may be diverted into the waste management system.

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 value of 548.5°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 change in performance of the regenerative HX is unchanged at EPU conditions, as discussed in the previous section, there is no effect on the performance of the letdown HX. The 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 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 is expected to 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 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. This programmed level will remain as currently installed with the revised average temperature program endpoints. The current setpoints for charging and letdown control remain appropriate for EPU conditions.

The portion of the expansion/contraction volume not accounted for by the pressurizer programmed level is made up by inventory from the VCT and if necessary, from safety-related 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 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. UFSAR Table 11.1-2 states that 40 gpm purification flow is sufficient at the current power level. 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 current licensing basis requirements with respect to GDC-29.
- Automatic diversion of letdown flow to the waste management system when the highest permissible water level is reached in the VCT.
- Provision of pressurizer auxiliary spray.
- 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 for each core re-load cycle.

The performance of the CVCS components, including valves and piping, that support containment isolation are not significantly 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 & Light (FPL) conducted a review of the St. Lucie Unit 1 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 inservice 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,
- 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 extended power uprate (EPU) may have on the above four items.

The acceptance criteria are based on GDC-4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture.

Specific review criteria are contained in SRP Section 3.6.2, and additional guidance is provided in Matrix 2 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for pipe rupture locations and associated dynamic effects 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 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.

Due to the application of leak-before-break (LBB) methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects associated with circumferential (guillotine) and longitudinal (slot) breaks do not have to be considered. A technical evaluation was performed to demonstrate that the probability of likelihood of such breaks occurring is sufficiently low that they need not be a design basis (see Reference 24 in UFSAR Section 3.6).

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 Class I seismic pipe which causes a LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

UFSAR Section 3.6 describes the design features that protect essential equipment from the consequences of postulated piping failures both inside and outside containment. The initial design bases were in accordance with guidance provided in letters sent by A. Giambusso, AEC Directorate of Licensing, in December 1972. This original guidance was supplemented by the issuance of NRC Regulatory Guide (RG) 1.46 in May 1973 for all systems except the RCS. The RCS used different criteria as discussed in UFSAR Section 3.6.2. The plant was then constructed with pipe whip restraints located and designed to comparable criteria that was less intensive from an analytical standpoint, yet provided more whip restraints than RG 1.46 would require. LBB criteria was then adopted as an alternative means to treat RCS hot leg and cold leg loop piping whip criteria per NUREG-1061. NRC Generic Letter (GL) 87-11 was adopted as an alternative means to provide pipe break protection for ASME Class 2, Class 3, and non ASME class systems to minimize the addition of or facilitate the removal of excess arbitrary intermediate pipe whip restraints. RG 1.46 was withdrawn in March 1985 as more current information was provided by the July 1981 revision of the Standard Review Plan, Section 3.6.2.

Postulated Piping Failures in Fluid Systems Inside Containment

High energy piping lines inside containment were evaluated for the effects of potential pipe breaks. Design basis pipe break criteria are presented in UFSAR Section 3.6.2. UFSAR Section 3.6.4 discusses design features provided to protect essential SSCs and to mitigate the consequence of piping failures.

Postulated Piping Failures in Fluid Systems Outside Containment

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 Appendices 3C and 3D.

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

> UFSAR Section 3.2, Classification of Structure, Components, and Systems, provides details with respect to the seismic 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, Mechanical System and Components, specifically Section 3.9.1, Dynamic System Analysis and Testing.

In addition to the licensing bases described in the UFSAR, the pipe rupture locations and associated dynamic effects were evaluated for St. Lucie Unit 1 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 is 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 has 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 3C, 3D, and 3J of the UFSAR. The purpose of postulation of pipe breaks is to comply with requirements of GDC-4, of Appendix A to 10 CFR 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 and jet impingement.

LR Section 2.5.1.3 addresses the impact of the EPU on piping system failures outside of 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 provides a list of high energy piping systems inside the primary containment for which pipe breaks are postulated to occur.

Design basis pipe break criteria are presented in UFSAR Section 3.6.2 and in Appendix 3.J.

UFSAR Section 3.6.4 discusses design features provided to protect essential SSCs and to mitigate the consequence of piping failures.

The current structural design basis includes the application of 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, Leak-Before-Break which describes the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis 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, Leak-Before-Break are credited in this LR with respect to excluding the dynamic effects of postulated ruptures in the RCS 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 have been retained, with the exception of the steam generator (SG) sliding base support and portions of the primary shield wall hot leg whip restraints removed for access to replace instrument nozzles. Refer to UFSAR Section 6.2.1.3.3 for changes to the reactor cavity pressure relief function. As a result of the installation of the replacement SGs, the shim plate attached to the SG sliding base support casting has been permanently removed, thereby deleting the north-south LOCA restraint for the SG sliding base support.

Postulated Piping Failures in Fluid Systems Outside Containment

The criteria for postulating pipe breaks for piping located outside containment are also presented in UFSAR Section 3.6.2 and in UFSAR Appendix 3.J.

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 Appendices 3C and 3D.

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, and 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 evaluations for EPU conditions did not result in any new or revised break locations. 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.
- Existing design of SSCs remain acceptable to protect safety-related SSCs 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 License Report (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 1 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 & 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 GDC-1, -2, -4, -14 and -15. FPL's review focused on the effects of the proposed extended power uprate (EPU) on the design input parameters and the design-basis loads and load combinations for normal, upset, emergency and faulted conditions. The FPL review covered the analyses of flow-induced vibration and the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The FPL review also included a comparison of the resulting stresses and cumulative usage factors (CUF) against code-allowable limits.

The acceptance criteria are based on:

- 10 CFR 50.55a and GDC-1, insofar as they require that structures, systems and components (SSC) 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

UFSAR Sections 3.1, 3.2, 3.5, 3.6, 3.7, 3.8, and 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 10 CFR 50.55a(a)(1) are as follows:

- 10CFR50.55a(a)(1) is described in UFSAR Section 5.2.1.3, Applicable Codes.

  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.

  All structures, systems and components 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 1. 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 are presented in Sections 17.1 and 17.2. A complete set of facility structural, arrangement and system drawings will be maintained under the control of FP&L throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FP&L. The classification of safety-related structures, systems and components is discussed in 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, 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 design basis earthquake (DBE). 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 DBE. 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 DBE.

  Design criteria for wind and tornado, flood and earthquake are discussed in 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.

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 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 associated with circumferential (guillotine) and longitudinal (slot) breaks do not have to be considered. A technical evaluation was performed to demonstrate that the probability of likelihood of such breaks occurring 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. Local missile barriers are 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 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 Class I seismic pipe which causes a 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.

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, 3.7.5, 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.

Reactor coolant system components are designed in accordance with the ASME Code Section III, and ANSI B 31.7. Quality control, inspection, and testing as required by this standard and allowable reactor pressure temperature operations ensure the integrity of the Reactor Coolant System.

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

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

Means are provided to detect significant leakage from the reactor coolant pressure boundary with monitoring readouts and alarms in the control room as discussed in UFSAR Chapters 5 and 12.

The pressure boundary has provisions for in-service inspection as described in UFSAR Section 5.2.5, to ensure continuance of the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with ASTM-E-185 is provided as discussed in UFSAR Chapter 5.

- 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 design criteria and bases for the reactor coolant system pressure boundary are described in the response to Criterion 14.

  The operating conditions established for the normal steady-state and transient operation and anticipated operational occurrences are discussed in Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin in maintained between the plant operating conditions and the design limits.

  The reactor protective system functions to minimize the deviation from normal operating limits in the event of certain anticipated operational occurrences; the results of analyses show that the design limits of the reactor coolant pressure boundary are not exceeded in the event of any anticipated operational occurrence.

In addition to the licensing bases described in the UFSAR, the pressure retaining components were evaluated for St. Lucie Unit 1 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 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 Licensing Report (LR) section addresses Nuclear Steam Supply System (NSSS) piping, components, and supports. Balance of plant (BOP) piping and supports are presented in LR Section 2.2.2.2. The NSSS piping, which is 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 the RCP to the RV. The RCS also includes a pressurizer, quench tank, and connecting piping.

The pressurizer is connected to loop 1B. 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 presented in LR Section 2.2.2.6; the Pressurizer and Supports are presented in LR Section 2.2.2.7.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis (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 fabricated in accordance with the rules and procedures of the ASME Code given in UFSAR Table 5.2-1. The anticipated transients listed in UFSAR Section 5.2.1.2 form the basis for the required fatigue analysis to ensure an adequate usage factor.

The reactor coolant piping is fabricated from ASME SA 516-Gr 70 carbon steel mill clad internally with roll bonded ASME SA 240 type 304L stainless steel. A minimum clad thickness of 1/8 inch is maintained. The 12-inch surge line is fabricated from ASTM A351 Gr CF8M, ASME SA-403, WP347; ASME SA-312, TP347 austenitic stainless steel.

Pressure and thermal stress variations associated with the design transients presented in UFSAR Section 5.2.1.2 are included in the engineering design of each of the RCS components, piping, and supports. In addition, the loads and moments resulting from the design transients are included in the design of equipment support foundations and interfacing support structures for the equipment.

The criteria applied in the design of the RCS supports are that the specific function of the supported equipment be achieved during all normal operating, seismic 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 Table 5.2-2. Refer to UFSAR Section 5.5.7.2 items “a” through “e” for additional information pertaining to NSSS supports.

The RCS support points are illustrated in UFSAR Figure 5.1-1.

The RCS in-service inspection is discussed in UFSAR Section 5.2.5.

Refer to LR Sections 2.2.2.3 through 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 5.2.1.2, Transients Used in Design and Fatigue Analyses, provides details of fatigue analyses required by the applicable codes listed in UFSAR Table 5.2-1.
- UFSAR Section 5.5, Component and Subsystem Design, provides details with respect to the design of NSSS structures, systems, and components.
- UFSAR Section 5.5.6, 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 St. Lucie Unit 1 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 evaluations for the EPU was to initially attempt to reconcile the existing design basis analysis results for a given structural analysis, relative to the 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 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 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 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 and Loss-of-Coolant Accidents, 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) and ANSI B31.7 (Reference 2), 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) and ANSI B31.7 (Reference 2). The surge line was subsequently evaluated to the acceptance criteria of ASME Code, Section III, 1986 (Reference 3) in order to include the effects of thermal stratification on stress and fatigue. The surge line thermal stratification evaluation was performed to address Reference 13. In part, Reference 13 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 13 are contained in Reference 4, which reported that the structural integrity of the pressurizer surge line is maintained for the transients due to thermal stratification.

The RCS hot leg surge and hot leg shutdown cooling nozzle dissimilar metal welds were preemptively repaired by weld overlay in 2008 in accordance with Reference 11 to address the potential for primary water stress corrosion cracking as discussed in EPRI MRP-169 in Reference 12. The repairs were analyzed per the requirements of ASME Code, Section III, 2001 Edition, 2003 Addendum for the applicable pre-EPU operating loads and found to be acceptable. In addition, a replacement design was evaluated for the hot leg RCS drain nozzle wherein the Alloy 600 nozzle-to-pipe safe end spool piece is replaced with a new stainless steel safe end, and a reconciliation was performed on the hot leg drain nozzle qualification and on the drain piping stress analysis.

The acceptance criteria for the NSSS primary equipment supports are based on the ASME B&PV Code (References 6, 7 and 8) as used in the current design basis.

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, Nuclear Steam Supply System Parameters, Nuclear Steam Supply System Parameters, 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 was evaluated and has a negligible effect on RCS stress and fatigue results. Consequently, a 1°F change in the through-wall thermal gradients for a subset of the design basis transients has a negligible effect on stresses and fatigue usage, which are due to the effects of the full set of transients.

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 ΔTs 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, Emergency Core Cooling System and Loss-of-Coolant Accidents, and the associated loop LOCA RV motions are addressed in LR Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports. Leak-Before-Break (LBB) eliminates pipe breaks from the RCS main loop piping (see LR Section 2.1.6, Leak-Before-Break). 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, because the larger original pipe break applied loads cause larger loads, displacements, and accelerations in the RCS. Therefore, the RCS piping LOCA analyses evaluation performed in Reference 5, which was based on the larger original mechanistic pipe breaks, remains applicable 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 UFSAR Section 3.7.2.3, 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 (Reference 3.2 of Reference 5) and DAGS (Reference 9) 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 pre-EPU design basis analysis in Reference 5 remain applicable for the EPU, as discussed in LR Section 2.2.2.1.2.1 Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RV Motions. In summary, large mechanistic breaks no longer have to be considered. Subsequently, while the results of Reference 5 are based on conservative pipe break inputs, 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.

For EPU, the hot leg operating temperature and operating transients were reviewed for potential impact on the analyzed repair designs for the hot leg surge, hot leg shutdown cooling, and hot leg drain nozzles. Since the hot leg operating temperature for EPU remain bounded by the current design transients and the EPU operating transients did not affect the pre-EPU operating conditions analyzed, the implementation of EPU does not impact the analysis of the noted repairs.

2.2.2.1.2.3 Evaluation of 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 were 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.

2.2.2.1.2.4 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, Maximum RCS Piping Stress and Usage Factor Results, for all RCS piping except the surge line, whose stresses and maximum CUFs are summarized in LR Table 2.2.2.1-2, Surge Line Stress and Usage Factor Results. The stresses are combined in accordance with the ASME code criteria as described in References 1, 2 and/or 3, as applicable. 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 all the surge line stresses and CUFs contained in LR Table 2.2.2.1-2 are for the current analyses of record (AORs) because they are not changed by the EPU.

The applicable RCS piping primary equipment support loads associated with the EPU parameters were evaluated and determined to be acceptable (see LR Section 2.2.2.3, Reactor Vessel and Supports; LR Section 2.2.2.5, Steam Generators and Supports; and LR Section 2.2.2.6, Reactor Coolant Pumps and Supports).

The RCP suction and discharge nozzle loads were compared to the allowables associated with the original equipment design. These nozzle loads are acceptable and the EPU has no adverse impact on the analysis results. See LR Section 2.2.2.6, Reactor Coolant Pumps and Supports for further discussion regarding the RCP nozzles.

The applicable RCS piping loads resulting from the EPU operating temperatures, as defined by the EPU NSSS parameters identified in LR Table 1.1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters, were evaluated for impact on LBB (see LR Section 2.1.6, Leak-Before-Break).

The EPU caused 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 tributary nozzles determined that the nozzle loads were acceptable. Furthermore, assessments of the branch piping systems attached to the RCS determined that the tributary piping system and support loads were acceptable.

For the pressurizer surge line, variations in the pressurizer and hot leg temperature difference due to the EPU, which affect the design transients as regards thermal stratification and fatigue analysis, have been evaluated. The limiting ΔTs for the pressurizer surge line are associated with the plant heatup and cooldown events that are not affected by the EPU.

As discussed in LR Section 2.2.2.1.2.1, Input Parameters, Assumptions, and Acceptance Criteria, the current design basis pressurizer surge line analysis results in Reference 4, 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

- 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, Maximum RCS Piping Stress and Usage Factor Results. The primary equipment nozzle loads are all acceptable. The RCS piping loads associated with the EPU are discussed in LR Section 2.1.6, Leak-Before-Break. 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; Section 2.2.2.5, Steam Generators and Supports; and Section 2.2.2.6, Reactor Coolant Pumps and Supports.

RCS piping displacements at the branch nozzles associated with the EPU have no significant impact on the branch piping systems that are attached to the RCS and 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, and the results in Reference 4 remain valid.

The current fatigue analysis bounds for the EPU conditions, and since the 40 year design transient set bounds 60 years of operation, the current fatigue analysis remains valid for the EPU for 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, Impact of EPU on Time-Limited Aging Analyses.

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 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, 1968 Edition, through Summer 1969 Addenda.
2. ANSI B31.7, Code for Nuclear Power Piping, Class I, Feb. 1, 1968 Draft Edition for Trial Use and Comment.
3. ASME Boiler and Pressure Vessel Code, Section III, for Nuclear Vessels, 1986 Edition.
4. CEOG Task 587, Report No. CEN-387-P, Rev. 1-P-A, Pressurizer Surge Line Flow Stratification Evaluation, May 1994.

5. Combustion Engineering Report NPSD-110, Revision 000, Reactor Coolant System Asymmetric Loads, Final Report, June 30, 1980.
6. ASME Boiler and Pressure Vessel Code, Section III, for Nuclear Vessels, 1965 Edition, through Winter 1967 Addenda.
7. ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, 1971 Edition, Including Through Winter 1973 Addenda.
8. ASME Boiler and Pressure Vessel Code, Section III, Appendix F, 1971 Edition, Including Through Winter 1972 Addenda.
9. Topical Report CENPD-168-A, Design Basis Pipe Breaks for the Combustion Engineering Two Loop Reactor Coolant System, Combustion Engineering Inc., June 1977.
10. 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.
11. St. Lucie Unit 1, Fourth Ten-Year Interval Unit 1 Relief Request 2, Docket No. 50-335.
12. EPRI Materials Reliability Program: Technical Basis for Preemptive Weld Overlays for Alloy 600 82/182 Butt Welds in PWRs (MRP-169), 1012843 Topical Report, September 2005.
13. NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, December 20, 1988.

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[1]

2.2.2.2 Balance of Plant Piping, Components, and Supports

2.2.2.2.1 Regulatory Evaluation

Balance of plant (BOP) piping and supports are reviewed as part of the extended power uprate (EPU). This section covers portions of Class 1 piping and its supports that are not included in LR Section 2.2.2.1, Nuclear Steam Supply System Piping, Components and Supports and 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 loop and pressurizer surge line.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis 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, provides details with respect to the seismic classification of piping and piping components.
- UFSAR Section 3.7, Seismic Design, Method of Analysis – Other Seismic Class I Systems provides details with respect to the seismic qualification of piping and piping components.
- UFSAR Section 3.9.2, ASME Code Class I and III Components provides details with respect to analysis and design of BOP piping, components and supports.

In addition to the licensing basis described in the UFSAR, the BOP piping, components and supports were evaluated for St. Lucie Unit 1 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 identifies 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 the portion of ASME Code Class 1 piping that is not addressed in the LR Section 2.2.2.1, Nuclear Steam Supply System Piping, Components and Supports. This evaluation also includes all Class 2 and 3 and non-nuclear piping that are part of the piping systems listed below.

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,
- Shutdown Cooling,
- Steam Generator Blowdown, and
- Turbine Cooling Water.

The licensing basis codes of record for BOP piping and supports, listed in UFSAR Section 3.9, are provided below.

- ANSI B31.1 Power Piping, 1967 Edition
- ANSI B31.7 Nuclear Power Piping, 1969 Edition
- American Institute of Steel Construction (AISC) Manual 7th Edition

The design basis codes of record for BOP piping and supports are listed below.

- ANSI B31.1 Power Piping, 1967 Edition
- ASME Boiler & Pressure Vessel Code, Section III, Nuclear Power Components, 1971 Edition through Summer 1973 Addenda. Reconciliation for the use of this Code was performed in accordance with ASME Section XI, paragraph IWA-7210(c).
- ANSI B31.7 Nuclear Power Piping, 1969 Edition
- American Institute of Steel Construction (AISC) Manual 7th Edition

However, later editions of above listed codes were used in some of the existing design basis calculations (as part of requalification efforts), such as the use of ASME Boiler and Pressure Vessel Code, 1989 Edition in the case of reactor coolant (RC) Loop branch pipe qualifications. While using these later editions of codes, appropriate code reconciliation of the later code edition with the original code of record was included in the documentation as part of justification for use of later editions.

Refer to LR Section 2.2.2.1, Nuclear Steam Supply System Piping, Components and Supports for discussion on the impact of EPU on reactor coolant piping, including the pressurizer surge line.

2.2.2.2.2.2 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:

Pre-uprate and EPU operating pressures, temperatures, and flow rates were obtained from heat balance diagrams, pipe stress calculations and other applicable plant documents.

Portions of the following piping systems experienced an increase in temperature, pressure, and/or flow rate resulting from EPU that required detailed pipe stress and/or pipe support evaluations:

- Main Steam,
- Condensate,
- Extraction Steam,
- Feedwater,
- Heater Drain, and
- Component Cooling Water.

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 $[(T_{EPU}-70°F)/(T_{Pre\text{-}Uprate}-70°F)]$, where T_{EPU} = Temperature at EPU conditions and $T_{Pre\text{-}Uprate}$ = 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.

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 LR Section 2.2.2.2.2.4.

Operating pressure increases due to EPU mostly affect systems related to the main power cycle (main steam, condensate, feedwater, extraction steam, 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, 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.

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 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).

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 GDC-2.

The method used to evaluate piping systems that experienced an increase in temperature, pressure, and/or flow rate is the preparation of detailed pipe stress computer analyses.

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.

For BOP piping systems that required detailed analyses to reconcile EPU operating parameters, a summary of revised pipe stress levels corresponding to EPU conditions for sustained loads, occasional loads, and thermal expansion loads is provided in LR Table 2.2.2.2-1. The results presented include existing stress levels, revised stress levels for EPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile EPU conditions. The design margin provided is based on the ratio of the calculated stress for EPU divided by the allowable stress.

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 are not currently described in the UFSAR and were used to calculate stresses and loads using the appropriate equations from the ASME III and/or ANSI B31.1 and B31.7 Codes. Using an approved quality assurance program, these computer programs have been verified and validated and shown to be accurate.

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 program is part of an integrated package “PepS,” which contains, besides the piping analysis core program, “PIPESTRESS”, and a program named “EDITPIPE”, its pre- and post-processor. 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 St. Lucie Unit 1 piping systems.

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 baseplates 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.

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 Boiler and Pressure Vessel 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.

STEHAM-PC

The STEHAM-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 STEHAM-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.
- Design of RCS and related components, including GDC-14 and GDC-15 requirements, is discussed in LR Section 2.2.2.1, Nuclear Steam Supply System Piping, Components and Supports, Class 1.

2.2.2.2.2.3 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 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.

The proposed pipe support additions and modifications for the condensate, feedwater and main steam system piping will not impact the License Renewal system evaluation boundaries. A description of modifications resulting from the implementation of EPU is presented in LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report. 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.

2.2.2.2.2.4 Results

LR Table 2.2.2.2-1 provides a summary of current or pre-EPU pipe stress levels, revised stress levels, current and revised CUFs, for EPU conditions and the resulting design margins for each piping analysis that required detailed evaluation to reconcile to EPU conditions. The code stress equations included in LR Table 2.2.2.2-1 address stresses due to thermal expansion, anchor displacements, sustained loads, fluid transient loads, and seismic loads, as applicable for EPU conditions. All calculated stress levels for EPU conditions remain within the respective code equation allowable values. Piping systems not specifically listed in LR Table 2.2.2.2-1 did not require detailed evaluation (i.e., no significant operating parameter increase due to EPU) to reconcile EPU conditions or involve piping and support systems which will experience plant modifications. The stress results reported have incorporated thermal expansion, branch pipe nozzle movement increases due to EPU (as is the case for RC Loop branch pipe qualification for EPU), and fluid transient increases, as applicable, that were reconciled as part of EPU evaluations.

The piping stress evaluations performed conclude that all piping systems will satisfy design basis requirements when considering the temperature, pressure, and flow rate and RC loop branch nozzle displacement effects resulting from EPU conditions, following implementation of the required pipe support modifications to accommodate the revised support loads due to EPU. The piping evaluations also concluded that, with modifications, the main steam piping can withstand the steam hammer loads associated with EPU conditions (resulting from a turbine stop valve closure event or an inadvertent main steam isolation valve closure event) and the feedwater piping system can withstand the water hammer loads associated with EPU conditions (resulting from a feedwater regulatory valve closure event or feedwater isolation valve closure event with feedwater pump trip).

The pipe supports were evaluated for increased loads due to EPU by performing manual calculations and/or detailed computer analyses, using the PC-PREPS and ANSYS computer programs. As described in LR Section 2.2.2.2.2.2, the PC-PREPS computer program performs a complete structural analysis, including an AISC code check, structural weld qualification and baseplate/anchor bolt qualifications. The ANSYS computer program uses finite element analysis methods to perform detailed welded attachment analyses.

The results of pipe support evaluations for systems impacted by EPU concluded that all supports remain acceptable, although certain BOP system pipe supports (such as main steam, feedwater, condensate) will require modification/addition to accommodate the revised loads due to EPU conditions. LR Table 2.2.2.2-2 provides specific information related to pipe support modifications (such as pipe support number, pipe size, location of supports and type of modifications made) associated with main steam, feedwater, and condensate systems. These pipe support modifications will be installed before the implementation of the EPU. Refer to LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report, for a summary of significant plant modifications.

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 2.2.2.2-3 and 2.2.2.2-4 list loads imposed on main steam and feedwater nozzles associated with Steam Generators. LR Table 2.2.2.2-7 describes the loads imposed on the discharge nozzle of feedwater pumps and their acceptability. LR Tables 2.2.2.2-5 and 2.2.2.2-6 describe loads imposed on containment penetrations for main steam and feedwater piping and their acceptability.

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 for a range of temperatures from 193°F to 473°F. Based on the analysis, the highest increase in LTOP stresses (at any location) of 3066 psi was conservatively added to the highest pre-EPU occasional stress of 7275 psi (at any location) to obtain 10,341 psi which is below the allowable of 17,150 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 level of flow induced piping vibration in BOP piping systems that compromise 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 power uprate. 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 St. Lucie Corrective Action system. 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 for St. Lucie Unit 1 to extensively monitor actual piping response to actual plant conditions. This method and plan, successfully implemented for EPUs, stretch power uprates (SPUs) and measurement uncertainty recapture (MURs) for several pressurized water reactors (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.

For St. Lucie Unit 1, the piping within the scope of the Power Uprate 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 St. Lucie Unit 1 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 1. 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, fifteen plant modifications will be implemented to preclude vibration failures at these analyzed locations. A total of six piping modifications and nine pipe support installations/modifications will be implemented prior to EPU implementation.

Walkdowns for power uprate observations will take place at EPU power level test plateaus (from 25% to 100% 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
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)
Charging line: Loop 1A2 Cold Leg (Class 1)	Equation 10	30,655	30,940	60,000	0.516
	CUF (Note 3)	0.1633	0.1648	1.0	0.1648
Charging line: Loop 1B1 Cold Leg (Class 1)	Equation 10	39,466	40,428	60,000	0.674
	CUF (Note 3)	0.7299	0.7496	1.0	0.75
Letdown Piping: Loop 1B1	Equation 10 (Note 5)	10,001	10,001	27,475	0.364
CCW: SR-14-8C Valve off of CFC Return	Equation 8	1,777	1,777	15,000	0.118
	Equation 10 (Note 5)	12,488	15,860	22,500	0.705
CCW: SR-14-8D Valve off of CFC Return	Equation 8	3434	3434	15,000	0.229
	Equation 11 (Note 5)	21,309	26,866	37,500	0.716
CCW: SR-14-8A Valve off of CFC Return	Equation 8	1845	1845	15,000	0.123
	Equation 10 (Note 5)	13,722	17,427	22,500	0.775
CCW: SR-14-8B Valve off of CFC Return	Equation 8	2478	2478	15,000	0.165
	Equation 10 (Note 5)	14,740	18,720	22,500	0.832
Containment Fan Cooler HVS-1A Return	Equation 8	2138	2138	15,000	0.143
	Equation 10 (Note 5)	12,848	16,317	22,500	0.725
Containment Fan Cooler HVS-1B Return	Equation 8	2069	2069	15,000	0.138
	Equation 10 (Note 5)	13,833	17,568	22,500	0.780
Containment Fan Cooler HVS-1C Return	Equation 8	1938	1938	15,000	0.129
	Equation 10 (Note 5)	16,054	20,389	22,500	0.906
Containment Fan Cooler HVS-1D Return	Equation 8	3177	3177	15,000	0.212
	Equation 10 (Note 5)	13,497	17,141	22,500	0.762

Table 2.2.2.2-1 (Continued)
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)
Containment Fan Cooler B Train Return	Equation 8	4729	4729	15,000	0.315
	Equation 11 (Note 5)	27,677	33,392	37,500	0.89
Containment Fan Cooler B Train Return (Evaluation of pipe wall reduction in penetration.)	Equation 8	3116	3116	15,000	0.208
	Equation 11 (Note 5)	20,972	25,941	37,500	0.692
Containment Fan Cooler A Train Return.	Equation 8	4044	4044	15,000	0.27
	Equation 11 (Note 5)	34,190	35,823	37,500	0.955
Condensate from Pumps 1A, 1B and 1C to Feedwater Pump Suction.	Equation 11 (Note 8)	(Note 4)	13,293	22,500	0.886
	Equation 13 (Note 8)		14,817	22,500	0.658
Feedwater Inside Containment: From containment penetration P3 to SG 1A.	Equation 8	5564	6384	15,000	0.426
	Equation 9U	5976	7000	18,000	0.389
	Equation 9E	6311	7986	27,000	0.296
	Equation 9F	(Note 4)	7986	45,000	0.177
	Equation 10	13,509	11,942	22,500	0.531
Feedwater Inside containment: From containment penetration P4 to SG 1B	Equation 8	5271	6158	15,000	0.411
	Equation 9U	7105	9162	18,000	0.509
	Equation 9E	7546	12,843	27,000	0.476
	Equation 9F	(Note 4)	12,843	45,000	0.285
	Equation 10	12,602	17,752	22,500	0.789
Feedwater Outside containment: Feedwater Pumps 1A & 1B	Equation 8	7930	8834	15,000	0.589
	Equation 9U	8100	15,566	18,000	0.865
	Equation 9E	(Note 4)	24,283	27,000	0.899
	Equation 9F	(Note 4)	24,283	45,000	0.54
	Equation 10	12,602	17,752	22,500	0.789
Heater Drain from MSR 1A to Heater 5B	Equation 10 (Note 5)	9937	11,994	22,500	0.533

Table 2.2.2.2-1 (Continued)
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)
Heater Drain from MSR 1B to Heater 5B	Equation 10 (Note 5)	21,771	15,593	22,500	0.693
Heater Drain from MSR 1C/1D to Heater 4A	Equation 11 (Note 5)	25,394	17,211	22,500	0.765
Heater Drain from MSR 1C to Heater 5A	Equation 10 (Note 5)	20,266	20,452	22,500	0.909
Heater Drain from MSR 1D to Heater 5A	Equation 10 (Note 5)	20,478	13,976	22,500	0.621
Heater Drain from MSR 1A/1B to Heater 4B	Equation 10 (Note 5)	9764	8488	22,500	0.377
Drain Coolers 1A/1B to Heater Drain Pumps 1A/1B	Equation 10 (Note 5)	16,917	17,594	22,500	0.78
Heater Drain Pumps 1A/1B Discharge Header to Heater 4A/4B	Equation 10 (Note 5)	13,830	14,383	22,500	0.64
Heater Vents from MSR 1C/1D to Heater 5A	Equation 8	9843	11,532	15,000	0.769
	Equation 13 (Note 8)	27,809	19,300	22,500	0.858
Heater Vents from MSR 1A/1B to Heater 5B	Equation 8	11,160	10,135	15,000	0.676
	Equation 13 (Note 8)	25,426	28,903	35,860	0.80
Extraction Steam from HP Turbine to Heater 5A	Equation 10 (Note 5)	2706	3406	22,500	0.151
Extraction Steam from HP Turbine to Heater 5B	Equation 10 (Note 5)	2926	3240	22,500	0.144
Main Steam Inside Containment: SG 1A to Cont. Penetration P1 (Note 5)	Equation 8	6742	7880	15,000	0.525
	Equation 9U	(Note 4)	15,868	18,000	0.882
	Equation 9E	(Note 4)	17,232	27,000	0.638
	Equation 9F	(Note 4)	17,232	45,000	0.383
	Equation 10	(Note 4)	6940	22,500	0.308

Table 2.2.2.2-1 (Continued)
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)
Main Steam Inside Containment: SG 1B to Cont. Penetration P2 (Note 5)	Equation 8	7485	7463	15,000	0.498
	Equation 9U	(Note 4)	17,549	18,000	0.975
	Equation 9E	(Note 4)	19,477	27,500	0.721
	Equation 9F	(Note 4)	19,477	45,000	0.433
	Equation 10	(Note 4)	6736	22,500	0.299
Main Steam Outside Containment: Penetrations P1 & P2 to Turbine Inlet (Note 5)	Equation 8	(Note 4)	9662	15,000	0.644
	Equation 9U	(Note 4)	13,187	18,000	0.733
	Equation 9E	(Note 4)	13,343	27,000	0.494
	Equation 9F	(Note 4)	13,343	45,000	0.297
	Equation 10	(Note 4)	21,819	22,500	0.970
Pressurizer Spray: Loop 1B1 & 1B2 RC Cold Leg (Class 1)	Equation 10	72,300	72,553	69,900	(Note 7)
	Equation 12	13,500	13,601	69,900	0.195
	Equation 13	55,800	56,219	69,900	0.804
	CUF (Note 3)	0.141	0.1593	1.0	0.1593
Safety Injection – Loop 1A1, RC Loop Cold Leg (Class 1)	Equation 10	53,527	61,395	59,025	(Note 7)
	Equation 12	11,742	13,468	59,025	0.228
	Equation 13	41,555	47,663	59,025	0.807
	CUF (Note 3)	0.0571	0.0651	1.0	0.0651
Safety Injection – Loop 1A2, RC Loop Cold Leg (Class 1)	Equation 10	55,593	61,819	59,025	(Note 7)
	Equation 12	11,682	12,990	59,025	0.220
	Equation 13	43,200	48,038	59,025	0.814
	CUF (Note 3)	0.0572	0.0662	1.0	0.0662
Safety Injection – Loop 1B1, RC Loop Cold Leg (Class 1)	Equation 10	58,304	66,233	59,025	(Note 7)
	Equation 12	9835	11,173	59,025	0.189
	Equation 13	38,670	43,929	59,025	0.744
	CUF (Note 3)	0.0701	0.0986	1.0	0.0986

Table 2.2.2.2-1 (Continued)
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)
Safety Injection – Loop 1B2, RC Loop Cold Leg (Class 1)	Equation 10	50,702	59,524	59,025	(Note 7)
	Equation 12	3982	4675	59,025	0.0792
	Equation 13	38,804	45,556	59,025	0.772
	CUF (Note 3)	0.0545	0.056	1.0	0.056
Shutdown Cooling – Loop 1A1 & 1A2, RC Hot leg (Class 1)	Equation 10	37,500	37,500	57,900	0.6477
	CUF (Note 3)	0.0086	0.0086	1.0	0.0086
Steam Generator Blowdown: SG 1A to containment penetration	Equation 8	8422	8422	15,000	0.561
	Equation 10 (Note 5)	18,669	18,669	22,500	0.83
Steam Generator Blowdown: SG 1B to containment penetration	Equation 8	9550	9550	15,000	0.637
	Equation 10 (Note 5)	10,498	10,498	22,500	0.466
Intake Cooling Water Piping (CW-1000)	Equation 8	5124	5124	15,000	0.342
	Equation 10 (Note 5)	4171	9176	28,138	0.33
Intake Cooling Water Piping (CW-1001)	Equation 8	4900	4900	15,000	0.327
	Equation 10 (Note 5)	4553	10,017	28,138	0.36

Table 2.2.2.2-1 (Continued)
Stress Summary at EPU Conditions

Piping Analysis Description (Note 6)	Loading Condition (Note 2)	Existing Stress (psi) (Note 4)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Note 1)

Notes:
1. Stress Interaction Ratio (also called "Design Margin") is based on the ratio of EPU stress divided by the Allowable stress or the EPU CUF divided by allowable CPU. Unless otherwise indicated, the pipe stress analysis equation numbers listed in this table correspond to ASME Section III, NB, NC/ND – 3650 equation numbers.
2. Unless otherwise indicated, the pipe stress analysis equation numbers listed in this table correspond to ASME Section III, NB, NC/ND – 3650 equation numbers.
3. CUF denotes Cumulative Usage Factor, applicable to ASME Section III, Code Class 1 piping.
4. When information is not provided, the information was not available.
5. For Class 2 piping, either the requirement of Equation 10 or Equation 11 (ASME Section III, Code Class 2 and 3) need to be satisfied. Hence, only the result of Equation 10 or Equation 11 (ASME Section III, Code Class 2 and 3) is listed.
6. Description is based on pipe stress analysis calculation number or piping segment of a given system included in the analysis. List includes Class 1 and Class 2/non nuclear piping. Class 1 piping are identified along with piping analysis description where applicable.
7. For Class 1 piping, if Equation 10 (ASME Section III, Code Class 1) exceeds the corresponding allowable stress, analysis requirements are satisfied by alternate rules permitted by ASME Section III Code Class 1 rules which require evaluation of Equation 12 and Equation 13 applicable to Code Class 1 piping.
8. Condensate system and heater vent system piping analyses are per USAS B31.1 Power Piping Code, 1967 Edition. Only the result of Equation 13 or 14 is listed as applicable.

Table 2.2.2.2-2
Pipe Support Modifications - EPU Conditions

Item	Support	System	Pipe Size (in.)	Building Location	Description/Type
1	MS-649-48B	MS	38	TB	Axial restraint (Modification of IWA)
2	MS-649-142B	MS	8	TB	Snubber (Move clamp on IWA)
3	MS-649-220	MS	8	TB	Vertical support (Modification of IWA)
4	MS-649-238	MS	8	TB	Vertical support (Modification of IWA)
5	MS-649-274	MS	38	TB	Axial restraint (Modification of IWA)
6	MS-649-601	MS	38	TB	Rigid strut (Baseplate structural member modification)
7	MS-649-731	MS	38	TB	Rigid strut (Baseplate structural member modification)
8	MSH-20	MS	38	TB	Uplift loads on rods (Replace with rigid struts)
9	MSH-55	MS	16	TB	Spring (Replace sprint)
10	MS-548-9	MS	34	CB	Snubbers (Replace snubbers and riser clamp)
11	MS-548-10	MS	34	CB	Rigid strut loads exceeds allowables (Replace with two struts)
12	MS-548-16B	MS	34	CB	Rigid strut (Reinforce structural members)
13	MS-548-5		34	CB	Member stresses exceed allowables (Reinforce structural members and welds)
14	MS-649-304A	MS	34	CB	Rigid strut (Replace clamp common to MS-649-304B)
15	MS-649-304B	MS	34	CB	Rigid strut loads exceeds allowables (Replace with larger strut)
16	MS-649-310	MS	34	CB	Pipe clamp exceeds allowable (Replace clamp)
17	MS-649-319	MS	34	CB	Member stresses exceed allowables (Reinforce structural members and welds)
18	MS-649-314	MS	34	CB	Snubbers (Replace snubbers with larger size)
19	BF-659-106	FW	20	TB	Rigid strut load exceeds allowable (Replace with large size rigid strut)

Table 2.2.2.2-2 (Continued)
Pipe Support Modifications - EPU Conditions

Item	Support	System	Pipe Size (in.)	Building Location	Description/Type
20	BF-659-260	FW	20	TB	Member and IWA stresses exceed allowables (Remove IWA's and reinforce structural members)
21	BF-659-7111	FW	20	TB	Axial restraint (Reinforce structural member)
22	BFH-10	FW	20	TB	Spring (Replace with spring trapeze assembly)
23	BFH-14	FW	20	TB	Spring (Replace spring)
24	BFH-16	FW	20	TB	Spring (Replace spring)
25	BFH-21	FW	24	TB	Uplift on rods (Replace rods with rigid struts)
26	BFH-25	FW	20	TB	Spring (Relocate existing pipe clamp)
27	BFH-54	FW	20	TB	Springs (Replace springs)
28	BFH-55	FW	20	TB	Vertical support (Modify stanchion)
29	BFH-59	FW	20	TB	Vertical support (Modify stanchion)
30	BFH-107	FW	20	TB	Rigid strut load exceeds allowable (Replace with large size rigid strut)
31	BFH-108	FW	20	TB	Rigid strut load exceeds allowable (Replace with large size rigid strut)
32	BF-659-42B	FW	20	TB	Lateral restraint member stresses exceeds allowables (Reinforce structural members and welds)
33	BF-659-188	FW	20	TB	Rigid strut load exceeds allowable (Replace with large size rigid strut)
34	BF-659-192A	FW	20	TB	Add axial rigid restraint
35	BF-659-605	FW	20	TB	Add axial rigid restraint
36	BF-659-1671	FW	20	TB	Add vertical restraint
37	BF-659-1770	FW	20	TB	Add lateral restraint
38	BF-659-1851	FW	20	TB	Add vertical restraint

Table 2.2.2.2-2 (Continued)
Pipe Support Modifications - EPU Conditions

Item	Support	System	Pipe Size (in.)	Building Location	Description/Type
39	BF-659-1861	FW	20	TB	Add axial rigid restraint
40	BF-659-1925	FW	20	TB	Add lateral restraint
41	BF-659-6165	FW	20	TB	Add lateral snubber
42	BF-659-7185A	FW	20	TB	Add lateral snubber
43	BF-659-7061	FW	16	TB	Member stresses exceed allowables (Reinforce structural members)
44	BFH-53	FW	20	TB	Spring (Reset sprint)
45	BF-549-11	FW	20	CB	Pipe clamp exceeds allowable (Replace clamp)
46	BF-549-8	FW	20	CB	Member stresses exceed allowables (Reinforce structural members and welds)
47	BF-661-407	FW	20	CB	Lateral snubbers (Replace existing IWA's)
48	BF-6610-416	FW	20	CB	U-bolt load exceeds allowable (Replace U-bolt)
49	CH-8	C	24	TB	Spring (Replace spring and rod)
50	CH-13	C	24	TB	Rod load exceeds allowable (Replace with larger rod)
51	CH-16	C	24	TB	Rod load exceeds allowable (Replace with larger rod)
52	CH-17A	C	24	TB	Uplift on rod (Replace rod with rigid strut)
53	CH-28	C	24	TB	Rod load exceeds allowable (Replace with larger rod)
54	CH-30	C	20	TB	Springs (Replace springs and rods)
55	CH-31	C	16	TB	Spring (Replace with spring trapeze assembly)
56	CH-31A	C	20	TB	Rod load exceeds allowable (Replace with larger rod)
57	CH-33A	C	20	TB	Rod loads exceed allowable (Replace with larger rods)
58	CH-36	C	20	TB	Rod load exceeds allowable (Replace with larger rod)
59	CH-38	C	20	TB	Rod load exceeds allowable (Replace with larger rod)

Table 2.2.2.2-2 (Continued)
Pipe Support Modifications - EPU Conditions

Item	Support	System	Pipe Size (in.)	Building Location	Description/Type
60	CH-39	C	24	TB	Springs (Replace springs)
61	CH-42	C	24	TB	Rod load exceeds allowable (Replace with larger rod)
62	CH-48	C	24	TB	Uplift on rod (Replace rod with rigid strut)
63	CH-55	C	24	TB	Pipe clamp load exceeds allowable (Replace pipe clamp)
64	CH-56	C	24	TB	Rod (Replace rod with spring)
65	CH-57	C	24	TB	Spring (Replace spring)
66	CH-61	C	24	TB	Spring (Replace spring)
67	CH-200	C	20	TB	Uplift on rod (Replace rod with rigid strut)
68	CH-205	C	20	TB	Lateral loads on U-bolt (Replace with structural members)
69	CH-208	C	20	TB	Lateral loads on U-bolt (Replace with structural members)
70	C-858-356	C	24	TB	Rigid strut and lateral restraints (Reinforce structural members)
71	C-858-390	C	24	TB	Rigid struts (Replace upper rigid strut with snubber)
72	C-858-5395	C	24	TB	Add spring trapeze assembly
73	C-858-5445	C	24	TB	Add rigid restraint
74	C-858-5818	C	24	TB	Add snubber
75	C-858-5875	C	24	TB	Add rigid restraint
76	HDH-184	HD	14	TB	Rod trapeze assembly (Replace structural member)
77	HDH-185	HD	14	TB	Spring (Replace with rigid strut)
78	HDH-188	HD	14	TB	Spring (Reset for cold load)
79	HDH-189	HD	14	TB	Spring (Replace spring)
80	HDH-190	HD	14	TB	Spring (Replace spring)
81	HDH-6608	HD	14	TB	Add rigid restraint

Table 2.2.2.2-2 (Continued)
Pipe Support Modifications - EPU Conditions

Item	Support	System	Pipe Size (in.)	Building Location	Description/Type
Notes: C = Condensate CB = Containment Building FW = Feedwater HD = Heater Drains IWA = Integral welded attachment MS = Main Steam TB = Turbine Building					

Table 2.2.2.2-3
Steam Generator Nozzle Loads
Main Steam Nozzles

Steam Generator 1A				
	Forces (Kips)		Moments (in-Kips)	
Description	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + DBE + THIST(TSV) + THER) (Note 1)	24	40	4644	2546
Total Loads =(DW + DBE + THIST(MSIV) + THER) (Note 1)	32	70	5252	2550
Steam Generator 1B				
	Forces (Kips)		Moments (in-Kips)	
Description	Axial (F_a)	Shear (F_V)	Bending (M_b)	Torsion (M_t)
Total Loads =(DW + DBE + THIST(TSV) + THER) (Note 1)	19	43	4310	3160
Total Loads =(DW + DBE + THIST(MSIV) + THER) (Note 1)	28	79	5213	3163

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 2.2.2.2-4
Steam Generator Nozzle Loads
Feedwater Nozzles

Steam Generator 1A				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads =(DW + DBE + THIST(FRV) + THER) (Note 1)	7	18	821	1653
Total Loads =(DW + DBE + THIST(FIV) + THER) (Note 1)	7	18	823	1655
Steam Generator 1B				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads =(DW + DBE + THIST(FRV) + THER) (Note 1)	14	21	1618	598
Total Loads =(DW + DBE + THIST(FIV) + THER) (Note 1)	14	20	1614	598

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 2.2.2.2-5
Containment Penetration Loads Summary
Main Steam Penetrations

Penetration P-1				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads (EPU)	171	41	7,679	8,241
Calculated Stress intensity (EPU)	48,446 psi			
Allowable Stress Intensity	61,141 psi			
Design Margin	0.79			
Penetration P-2				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads (EPU)	151	46	8483	8426
Calculated Stress Intensity (EPU)	47,420 psi			
Allowable Stress Intensity	61,141 psi			
Design Margin	0.78			

Table 2.2.2.2-6
Containment Penetration Loads Summary
Feedwater Penetrations

Penetration P-3				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads (EPU)	48	24	3151	228
Calculated Stress intensity (EPU)	39,111 psi			
Allowable Stress Intensity	60,520 psi			
Design Margin	0.65			
Penetration P-4				
Description	**Forces (Kips)**		**Moments (in-Kips)**	
	Axial (F_a)	**Shear (F_V)**	**Bending (M_b)**	**Torsion (M_t)**
Total Loads (EPU)	41	22	2965	176
Calculated Stress Intensity (EPU)	38,884 psi			
Allowable Stress Intensity	60,520 psi			
Design Margin	0.64			

Table 2.2.2.2-7
Feedwater Pump Nozzle Load Summary

Equipment: Feedwater Pump 1A						
Case Number	**FX (lbs)**	**FY (lbs)**	**FZ (Axial) (lbs)**	**MX (ft-lbs)**	**MY (UP) (ft-lbs)**	**MZ (Torsion) (ft-lbs)**
Deadweight	-72	-201	-68	98	-266	-1049
ABSMAX (TH-1, TH-2, TH-3, TH-4)	-1539	-1656	-1479	3159	-3445	-2081
MAX (FRV, FIV)	168	728	620	411	385	833
Static Total	1611	1857	1547	3257	3711	3130
Dynamic Total	1779	2585	2167	3668	4096	3963
2xAPI Allowable	3200	2600	4000	9400	7000	4600
Static Interation Ratio	0.50	0.71	0.39	0.35	0.53	0.68
Dynamic Interation Ratio	0.56	0.99	0.54	0.39	0.59	0.86

Notes:

ABSMAX = Absolute Maximum Value
MAX = Maximum Value
TH-1 = Thermal Mode 1 – All ON
TH-2 = Thermal Mode 2 – Feedwater Pump 1B OFF
TH-3 = Thermal Mode 3 – Feedwater Pump 1A OFF
TH-4 = Thermal Mode 4 – All OFF (40 °F)
FRV = Feedwater Regulating Valve closure transient
FIV = Feedwater Isolation Valve closure transient
Static Total = MAX (Deadweight, Deadweight +TH_{MAX})
Dynamic Total = MAX (FRV, FIV) + MAX (Deadweight, Deadweight +TH_{MAX})
Interaction Ratio = Static Total/2xAPI Allowable
Dynamic Interaction Ratio = Dynamic

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. The RV is described in UFSAR Sections 4.1, 3.9, and 5.4. The RV supports are described in UFSAR Sections 3.8.5.1, 3H, and 5.5.7.2.

The RV, as the principal component of the reactor coolant system (RCS), contains the heat-generating core, coolant circulating channels and RV internals. Primary outlet and inlet nozzles provide for the exit of heated reactor coolant and its return to the RV for recirculation through the core.

In 1983, the thermal shield was removed from the RV, and a re-analysis of the core support barrel (CSB) and the reactor internals without the thermal shield was performed. The component stresses under normal, upset and faulted conditions were evaluated and found to be within the limits of Section III, Subsection NG 1972, Draft Edition of the ASME Nuclear Components Code.

In 2005, a replacement reactor vessel closure head (RVCH) was installed.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis in LR Section 2.2.2 applies to the RV and its supports, with the following amplifications.

The RV is designed and fabricated in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class A, 1965 Edition through Winter 1967 Addenda. A general discussion of materials specifications is given in UFSAR Section 5.2.3, with types of materials listed in UFSAR Table 5.2-4.

Class A vessels are analyzed in accordance with the ASME B&PV Code requirements. The maximum stress intensities and cumulative usage factors are in compliance with the Code values.

The supplementary loading combinations originally applied to the RVCH addressed pipe rupture and seismic loading combinations not addressed by the ASME B&PV Code of Record (1965 Edition through winter 1967 Addenda). These loadings are addressed for the replacement RVCH in the certified design specification, as required by Section III of the ASME B&PV Code 1989 Edition, No Addenda.

UFSAR Section 5.4 states in part that the RV bottom head, cylindrical shell courses and RV head lifting lugs are made of SA 533-65, Grade B, Class I material. The RV top head is made from a one piece forging of SA-508 Class 3 material. The RV closure flange is a forged ring with a machined ledge on the inside surface to support the reactor vessel internals (RVI). No ring forgings are used for RV shell sections. The flange is drilled and tapped to receive the closure studs and is machined to provide a mating surface for the RV closure seal.

Six radial nozzles on a common plane are located just below the RV closure flange. Extra thickness in this vessel-nozzle course provides the reinforcement required for the nozzles. Additional reinforcement is provided for the individual nozzle attachments. A boss located around each outlet nozzle on the inside diameter of the vessel wall provides a mating surface for the internal structure which guides the outlet coolant flow. This boss and the outlet sleeve on the CSB are machined to a common contour to minimize core bypass leakage. A hemispherical head forms the lower end of the vessel shell. There are no penetrations in the lower head.

The removable top closure head is hemispherical. The head flange is drilled to match the vessel flange stud bolt locations. The 54 stud bolts are fitted with spherical crowned washers located between the closure nuts and head flange, to maintain stud alignment during head flexing due to bolt-up. To ensure uniform loading of the closure seal, the studs are hydraulically bolt-tensioned.

The RV integral supports consist of three pads welded to the underside of one outlet and two inlet RV nozzles, in turn supported by graphite lubricate bearing plates. The arrangement of the RV supports allows radial growth of the RV due to thermal expansion while maintaining it centered and restrained from movement caused by seismic disturbances.

The RV and its supports are designed to withstand stresses originating from various operating and design transients described in UFSAR Section 5.2.1.

The RV is supported on a built-up steel girder column combination anchored into the shield concrete at elevation 23 ft. The built-up steel column is anchored into the concrete base at elevation - 2.92 ft of the reactor building.

Pressure and thermal stress variations associated with the design transients presented in UFSAR Section 5.2.1.2 are included in the engineering design of each of the RCS components, piping, and supports. In addition, the loads and moments resulting from the design transients are included in the design of equipment support foundations and interfacing support structures for the equipment.

Inservice inspection (ISI) of the RCS is based on a ten-year interval as required by the ASME B&PV Code, Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems, and is defined in the ISI program. Additional information relative to ISI is described in UFSAR Section 5.2.5.

UFSAR Table 5.4-1 provides RV parameters.

In addition to the licensing bases described in the UFSAR, the RV and supports were evaluated for St. Lucie Unit 1 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 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 BLPB analysis results are combined in accordance with the SAR 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 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 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 (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 branch line pipe breaks (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 1.1, Nuclear Steam Supply System Parameters and Section 2.2.6, NSSS Design Transients to those considered in the analyses of record (AORs) for the RV. The impact of changes in full power operating temperatures on 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 deemed 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, Nuclear Steam Supply System Piping, Components 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 normal operating temperatures (NOT) associated with the EPU.

EPU effects on the existing seismic and pipe break design basis results, and the resulting stresses due to the required load 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, Nuclear Steam Supply System Piping, Components and Supports. 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. This small change was evaluated and has a negligible effect on RCS stress and fatigue results. 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 CSB snubber lugs). 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. 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% temperature increase has a negligible effect on the stresses and the cumulative usage fatigue (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 consistent with the AOR was performed as part of the overall evaluation. The temperature change in the plant loading and unloading transient due to the EPU was considered negligibly small for this analysis. All currently specified transients were applied to the flow skirt normal flow analysis.

A flow-induced vibration evaluation of the flow skirt was also performed for the EPU. This evaluation considered the AOR for both the St. Lucie Units 1 and 2 flow skirts, and arrived at the conclusion that the St. Lucie Unit 1 flow skirt design remains valid for EPU effects. The St. Lucie Unit 2 AOR was considered for this evaluation because this AOR was performed using finite element analysis methods for determining the natural frequencies of the flow skirt. This methodology was deemed to have produced more accurate results than the methodology used in the St. Lucie Unit 1 AOR. The geometries of both units flow skirt designs were compared to justify the use of St. Lucie Unit 2 results in the St. Lucie Unit 1 flow-induced vibration evaluation.

Structural Steel Supports (Steel Beams and Columns)

The reactor vessel is supported at three points on a steel girder-column assembly within the reactor cavity. The 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 girder and to the reactor cavity floor at elevation -2.92 ft.

The support shoes welded to the RV nozzles are free to slide along the axis of the nozzles transmitting a frictional load to the support structure in the longitudinal 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 ventilates the reactor support girders and removes 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 and support design loads in LR Table 2.2.2.3-4. Support nomenclature is as shown on LR Figure 2.2.2.3-1. EPU thermal loads are lower than pre-EPU loads and EPU DWt loads are slightly higher than pre-EPU. However, EPU DWt loads are lower than the original design thermal loads (same stress allowable), therefore the EPU DWt loads are bounded by the original design. The DWt plus thermal load combination (NOT) is also bounded by the original design.

A thermal analysis of the reactor cavity under EPU conditions using an ANSYS 3D model of the reactor support girders and shield wall was prepared to evaluate the effect of the increased EPU power on the temperatures in the reactor cavity. Results of the analysis 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 the 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 the UFSAR remain valid for EPU conditions.

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. EPU conditions result in minimal changes from current plant conditions and the replacement RCVH weighs slightly less than the original closure head and is otherwise identical to the original in form, fit and function. The core ledge normal operating loads, which are due to the RVI weights and the force exerted on the core ledge by the RVCH, RV head area equipment, and the RVCH holddown device do not change due to the EPU. Therefore, it has been determined that the current design basis results for the replacement RVCH, core ledge and closure head studs 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 B&PV 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 B&PV 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 thermal loads on structural supports are lower than pre-EPU loads and EPU DWt loads are slightly higher than pre-EPU loads. However, EPU DWt loads are lower than the original design thermal loads (same stress allowable); therefore the EPU DWt 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 distribution of temperatures is very similar between EPU and pre-EPU and that the magnitude of the temperatures from the ANSYS EPU calculations are lower than the pre-EPU conditions included in the UFSAR for 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, 1965 Edition up to and including the Winter 1967 Addendum.
2. ASME Boiler and Pressure Vessel Code, 1989 Edition, No Addenda.

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

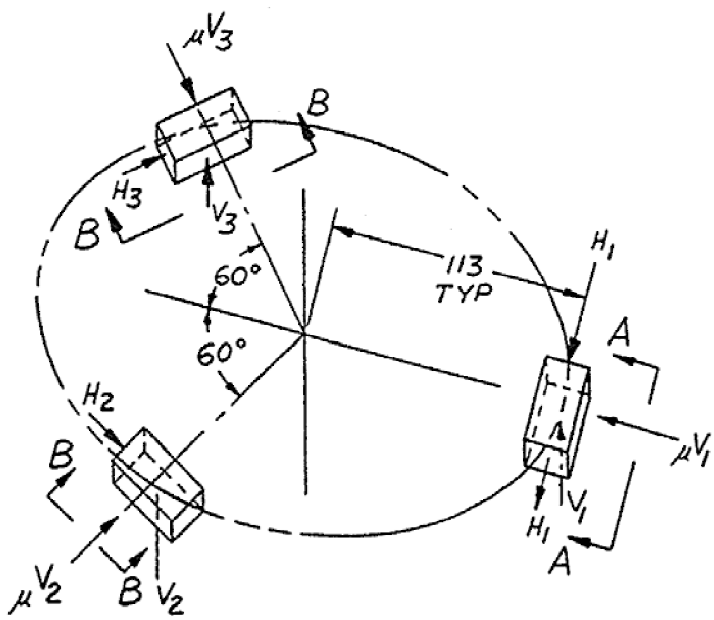
Table 2.2.2.3-2
Surveillance Holder Results Summary

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)		Original Design (kips)	
	Thermal	Deadweight	Thermal	Deadweight	Thermal	Deadweight
H1	36	0	0	0	28	0
V1	617	703	510	722	1155	666
H2	36	0	0	0	91	0
V2	616	703	94	709	726	634
H3	36	0	0	0	79	0
V3	618	703	96	709	741	634
F	±396		±370		±540	

Figure 2.2.2.3-1
Reactor Vessel Support Reactions



2.2.2.4 Control Rod Drive Mechanism

2.2.2.4.1 Introduction

St. Lucie Unit 1 refers to the control rod drive mechanisms (CRDM) as the control element drive mechanisms (CEDM). FPL's 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 pressure-retaining components of the CEDM 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 GDC. This review addressed material compatibility with primary system fluids and the 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 SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; other guidance is provided in Matrix 2 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

The generic the current licensing basis (CLB) discussed in LR Section 2.2.2 applies to the CEDMs. The CLB in LR Section 2.2.2 describes the GDC and related guidance applicable to this review of reactor coolant system pressure retaining components and component supports (CEDMs, pressurizer, reactor coolant pumps, reactor vessel (RV) structure, steam generators). The applicable regulations are: 10 CFR 50.55a and GDC-1-2, -4, -14 and -15.

The CEDMs are designed to function during and after all normal plant transients of temperature and pressure.

The CEDMs are designed to function during and after an operational basis earthquake. The CEDM is capable of tripping or inserting the CEAs after a design basis earthquake. For pipe break accident loads, the CEDMs are designed to maintain the position of the CEAs in the core.

The CEDMs are mounted and welded to nozzles on top of the reactor vessel closure head (RVCH). The CEDMs consist principally of the motor assembly, upper pressure housing, and coil stack assembly. The drive power is supplied by the coil stack assembly, which is positioned around the CEDM housing. The CEDMs are forced air cooled. Each CEDM is capable of withdrawing, inserting, holding or tripping the CEA from any point within its travel in response to operating signals. Each CEDM is connected to the CEA by an extension shaft.

The CEDM pressure housings are an extension of the RV and a part of the RCPB, and are designed to meet the requirements of Section III of the ASME Boiler and Pressure Vessel Code Class A 1998 Edition through 2000 Addenda. Pressure and thermal transients and steady-state loadings are evaluated in the design analysis. A summary of the RV stress limits is provided in UFSAR Section 5.2.1.

UFSAR Section 4.2.3.1.3 describes testing performed on the CEDMs.

It is noted that the CEDMs were replaced as part of the RVCH replacement effort.

In addition to the licensing basis described in the UFSAR, CEDMs were evaluated for St. Lucie Unit 1 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.

2.2.2.4.2 Technical Evaluation

2.2.2.4.2.1 Introduction

The CEDMs are designed and analyzed to meet the ASME Code 1998 Edition with Addenda through 2000. 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, and RV 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 RV head, it experiences no additional flow induced vibration other than the RV 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 RV head excitation due to seismic, LOCA, pump pulsation and random turbulence is not impacted by the EPU.

2.2.2.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

No changes were made to the analytical methodologies, assumptions, ASME Code Editions, and computer programs used to evaluate the CEDMs for EPU conditions.

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 and upper pressure housing.

The CEDM nozzle is not within the scope of this LR section; 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 four cases of Performance Capability Working Group (PCWG) parameters developed for the EPU program. 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 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 at EPU conditions. Therefore, there is no impact on the stress intensities.

2.2.2.4.2.4 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 NSSS design transient values are bounded by the NSSS design transient values associated with the CEDM analysis of record. Therefore, there is no impact on the stress intensities or cumulative usage factors.

2.2.2.4.2.5 Evaluation of 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.

2.2.2.4.2.6 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) are bounded by the parameters and transients used for the analysis of record. The seismic, LOCA, pump pulsation and random turbulence loads are not impacted by the EPU.

Therefore, the results of the current analysis of record remain bounding and applicable to the St. Lucie Unit 1 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 fatigue usage factors for each of the CEDM pressure boundary components for EPU conditions is presented in Tables 2.2.2.4-2 through 2.2.2.4-7. 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 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. 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 2.2.2.4-7

Design Conditions (NB-3221)

Pm < Sm

PL < 1.5Sm

PL + Pb < αSm

Level A and Level B Conditions (NB-3222 and NB-3223)

PL + Pb + Q (range) < 3Sm

Cumulative Fatigue Usage Factor < 1

Level C Conditions (NB-3224)

Pm < Greater of [1.2Sm; Sy]

PL + Pb < Greater of [1.2αSm; αSy]

For the motor housing Ferritic material (ASTM 276 Type 403 Condition T), the criteria for pressure only loading is (NB-3224.1)

Pm < Greater of [1.1Sm, 0.9Sy]

Level D Conditions (Appendix F)

Pm < Lesser of [2.4Sm; 0.7Su]

PL + Pb < Lesser of [3.6Sm; 1.05Su]

Test Conditions (NB-3226)

Pm < 0.9Sy

Pm + Pb < 1.35Sy when Pm < 0.67Sy, or

Pm + Pb < (2.15Sy – 1.2Pm) when 0.67Sy < Pm < .9Sy

Shear Stress (NB-3227.2)

Shear Stress < 0.6Sm

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)

Table 2.2.2.4-1 (Continued)
ASME Code Criteria and Nomenclature Used in LR Tables 2.2.2.4-2 through 2.2.2.4-7

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
Sy = yield stress
Su = tensile strength
U = cumulative fatigue usage factor
$\sigma_1 + \sigma_2 + \sigma_3$ = three primary principle stresses
α = 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
EPU Design Conditions @ 650°F
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-3
EPU Level A and Level B Conditions
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-4
EPU Level C Conditions
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-5
EPU Level D Conditions
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-6
EPU Test Conditions
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-7
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 UFSAR Sections 5.2, 5.3, and 5.5.1. The SG supports are described in UFSAR Section 5.5.7.2. St. Lucie Unit 1 uses two Babcock & Wilcox (B&W) replacement SGs. 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. Supports,
2. Structural integrity,
3. Design pressure differential,
4. Thermal-hydraulic performance,
5. Flow-induced tube vibration and wear,
6. Tube integrity,
7. Loose parts and foreign objects,
8. Tube hardware,
9. Steam drum, and
10. Chemistry.

A summary regarding the adequacy of the SGs and their supports under EPU conditions concludes this LR subsection.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis 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 exchangers 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 centrifugal cyclone 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 5.5.1.3 states that each SG is designed for the transients listed in UFSAR Sections 5.2.1 and 5.5.1.1, according to the requirements of the ASME B&PV Code, Section III. Normal and upset conditions (Levels A&B) are evaluated considering both stress limits and cyclic fatigue according to the ASME B&PV Code. The cumulative usage factor is less than 1.0. Emergency and faulted conditions Levels C&D are evaluated according to their respective ASME B&PV Code allowable stresses and to ensure structural integrity and safe shutdown of the SGs.

UFSAR Section 5.5.1.2 states that the SG U-tubes are given Inconel composition Alloy 690. The tube-to-tube sheet joint is welded on primary side before the tubes are hydraulically expanded in the tube sheet holes. Divider plates in the lower head separate the inlet and outlet plenums. The plenums are carbon steel forging with stainless steel clad. The reactor coolant side of the tube sheet is nickel-chromium-iron clad.

UFSAR Section 5.5.1.3 states that the SG has also been designed to ensure that critical vibration frequencies will be well out of the forcing function frequency range expected during normal operation and during abnormal conditions. The SG tubing and tubing supports are designed and fabricated with consideration given to both secondary side flow induced vibrations. In addition, the heat transfer tubing and tube supports are designed such that they will not be structurally damaged under the loss of secondary pressure conditions that may produce a fluid velocity, through the steam outlet nozzle, four times the design velocity.

Although similar in general design concept and capacity, the SGs utilize materials that have improved resistance to known corrosion issues affecting pressurized-water reactor (PWR) SGs.

UFSAR Section 5.5.7.2 states that the SG is supported at the bottom by 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 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). The top of each unit is restrained from sudden lateral movement by keys and hydraulic snubbers mounted rigidly to the concrete structure.

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 Table 5.2-2. The criteria is used to determine the loads the supports must consider as a result of the effects of pipe rupture and seismic conditions.

For a discussion pertaining to the evaluation of RCS components supports for asymmetric LOCA loads, see UFSAR Section 3.6.3.1.

UFSAR Section 5.2.1 summarizes RCS design transients, 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.

In addition to the licensing basis described in the UFSAR, the SGs and supports were evaluated for St. Lucie Unit 1 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 10 areas identified in LR Section 2.2.2.5.1 are discussed in LR Sections 2.2.2.5.2.1 through 2.2.2.5.2.10.

2.2.2.5.2.1 Supports

2.2.2.5.2.1.1 Introduction

The lower SG sliding base (SGSB) supports described in UFSAR Section 5.5.7.2b have been evaluated for EPU. The reactor coolant loop (RCL) piping loads on the SGSB supports due to the parameters associated with the EPU discussed in LR Section 2.2.2.1, Nuclear Steam Supply System Piping, Components and Supports, 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), safe shutdown earthquake (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.

2.2.2.5.2.1.2 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.

Acceptance Criteria

The sliding base plate (SBP) was designed in accordance with the ASME B&PV Code, Section II, 1971 Edition, No addenda (Reference 1). The SBP is considered a support structure; therefore, it is reanalyzed for EPU in accordance with Subsection NF and Appendix F of the ASME B&PV Code Section III. Acceptance criteria for normal operation (NOP) loads are based upon Subsection NF of Reference 2 and acceptance criteria for faulted loads are based on Appendix F of Reference 3.

Acceptance criteria for the concrete foundation is ACI 318-63 (Reference 4).

2.2.2.5.2.1.3 Description of Analyses and Evaluations

The SGs are supported by a SBP bolted to the integral conical skirt, mounted on low friction bearing plates on top of the concrete foundation. Keyways embedded in the concrete limit lateral motion during a seismic event and following a LOCA. Keys and snubbers at the upper end guide restrain the SGs during seismic events and following a LOCA or steam line break.

DWt and 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 LR Table 2.2.2.5-1.

A detailed three dimensional finite element model of the SBP was created and analyzed using ANSYS Version 11.0. The SBP stresses due to NOP, seismic, and branch line pipe break (BLPB) loads were calculated and evaluated using the criteria of the ASME B&PV Code, Subsection NF and Appendix F, References 2 and 3.

The foundation was analyzed for forces resulting from any one load or their combination, whichever is critical. Horizontal forces are transferred by shear keys. These keys are checked for shearing and bearing stresses. Moment and uplift forces are transferred by anchor bolts embedded in the concrete foundation. Critical loads were selected among sixteen pipe rupture cases associated with a LOCA. Normal operation loads (DWt + thermal expansion at full power) are bounded by accident conditions loads.

2.2.2.5.2.1.4 Results

The results of the SBP analysis concluded that both SG1A and SG1B front pads (SG pads closest to the reactor vessel, Y1 in LR Figure 2.2.2.5-1) lift off under NOP conditions, and the SG1B side pads (Y2 and Y4) lift off slightly. NOP gaps between the SG pads and the sliding base are shown in LR Table 2.2.2.5-2. The vertical uplift is bounded by the pre-EPU design since the EPU displacements were obtained from a model using a heavier SG, heavier reactor coolant pump (RCP) motors and a negligible rise in EPU temperature of 1oF.

Analysis of the SBP for the maximum vertical loads concluded that all ASME stress criteria are met for NOP and faulted analyses. For NOP loading, the maximum stress ratio is 0.85 due to the primary plus secondary stress check. The primary plus secondary stress is 52.29 ksi, which is less than the 3Sm allowable of 69.90 ksi. For the faulted condition loading, the vertical load, 7355 kips, is less than the 0.7 collapse load of 15,057 kips. The faulted shear stress, 22.91 ksi, is less than the 26.06 ksi allowable shear stress.

Vertical loads on the foundations for the DWt case are generally higher as a result of EPU, however, the vertical loads for NOP are lower (LR Table 2.2.2.5-1). The increase in total DWt load was evaluated and found to be bounded by the pre-EPU design basis loads.

SGSB 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, Nuclear Steam Supply System Piping, Components and Supports remain bounded by the current design basis SG support loads.

2.2.2.5.2.1.5 References

1. ASME Boiler and Pressure Vessel Code Section II, 1971 Edition, No Addenda.
2. ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, 1971 Edition, through Winter 1973 Addenda.
3. ASME Boiler and Pressure Vessel Code, Section III, Appendix F, 1971 Edition, through Winter 1972 Addenda.
4. ACI 318-63 Building Code Requirements for Reinforced Concrete.

2.2.2.5.2.2 Structural Integrity

2.2.2.5.2.2.1 Introduction

To quantify the range of stress occurring during each postulated design transient for the EPU conditions, ratios were determined between the EPU and design basis pressure and temperature variations and the design basis range of stresses were prorated by these ratios. Acceptance of the results for EPU conditions was based on demonstrating continued compliance with the structural criteria in the ASME B&PV Code Section III, Subsection NB (Reference 1). These acceptance criteria are the same as those used for the design basis analyses of the Replacement SGs.

The internal components, which are not part of the pressure boundary, are not governed by the ASME B&PV Code (Reference 1). However, ASME B&PV Code, Section III, Subsections NB and NF were adopted as guidelines for performing the structural analysis of these components.

The scope of the reconciliation was the entire SG pressure boundary, internal and external pressure boundary attachments, and all internal components. Specifically, reconciliations were performed for the tubesheet, stay-cylinder, U-tubes, primary head and vessel support skirt, secondary shell and internal/external attachments, primary and secondary nozzles, primary and secondary manways, handholes, inspection ports, studs and covers on all bolted openings, lattice grid and U-bend tube supports, shroud, and steam drum internals.

2.2.2.5.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The structural integrity evaluation of the SGs was performed using the EPU licensed core rated power level of 3020 MWt (NSSS thermal power level of 3034 MWt), SG tube plugging (SGTP) over the range from 0 to 10 percent, with a primary inlet temperature of 551°F, primary inlet pressure of 2250 psia, a full load SG outlet pressure ranging from 860 to 840 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 pre-EPU design basis analyses against the EPU SG design transients and the EPU nozzle interface loads.

The range of stress occurring during a transient is related to the temperature and pressure variation during that transient. The change in the range of stress occurring during each postulated transient for the EPU relative to the design basis can be determined by taking the ratio of the new variation under the EPU conditions to the old variation and prorating the stress range results. A detailed comparison was performed between the EPU and design basis transients to determine these temperature and pressure variation ratios. Variations were compared for the primary side inlet and outlet temperatures, secondary side temperatures, primary side pressures, and secondary side pressures. The bounding ratios were used to prorate the stress results. Where the temperature histories were considered to be too dissimilar for a meaningful comparison, ratios were not calculated and a more detailed reconciliation using finite element analysis was performed.

The Replacement SGs began operation in 1998 and are qualified for the equivalent of 40 years of the design basis transients. Operation at the EPU conditions will begin no earlier than 2011. For simplicity, all components, except for the studs on the pressure boundary bolted openings, were considered to operate at the EPU conditions for the full 40-year design life. A reduction in the number of design cycles was considered for the pressure boundary studs to produce an acceptable fatigue usage factor under EPU conditions. Specifically, the number of design cycles specified for the plant loading/unloading transient was reduced since this transient accounts for the majority of fatigue damage for studs.

The seismic loading of the internals was concluded to be unaffected by the EPU and the pre-EPU design basis loads were used. Since there are no operating conditions loads on the SG external clevis lug and shear keys, the pre-EPU design basis loads were used in the reconciliation analyses. The bolt preloads for bolted pressure boundary openings were established on the basis of “leak proofing” the joints. The pre-EPU design basis preloads were used in the reconciliation analyses.

Changes in the water film velocities and operating temperatures for the EPU operating conditions may affect the flow-assisted corrosion (FAC) rates. FAC is only relevant for the SG secondary side, since the primary side surfaces are fully clad with high chromium material. The analysis of record for the secondary side design corrosion allowances is where FAC rates and design corrosion allowance values were determined at locations in the SG where FAC is most critical based on a consideration of [ ]^{a,c}. An assessment of the FAC rates at EPU conditions was performed and [ ]^{a,c}. Periodic inspection of the SGs is addressed in the Steam Generator Integrity Program.

The design basis analysis for pre-EPU conditions demonstrated protection against non-ductile fracture for the SG pressure boundary in conformance with 10 CFR 50 Appendix G and ASME Section III Appendix G. That evaluation is unaffected by the EPU, since non-ductile fracture is a phenomenon that occurs only at low temperatures. The EPU only affects full power operation where temperatures are 532°F or greater. This is well above the nil-ductility transition temperature for the pressure boundary materials. As a result, the current design basis analysis demonstrating protection against non-ductile fracture remains applicable for the EPU conditions.

Acceptance Criteria

The acceptance criteria from ASME B&PV Code Section III, Subsection NB for Class 1 components (Reference 1) were used for the structural evaluation of the primary and secondary pressure boundary components consistent with the current SG design basis analysis. The criteria ensure that excessive plastic deformations are 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 the adequacy of the SG design for operation at the EPU conditions for the remainder of the 40-year design life.

The SG internal components, other than the U-tubes, including pressure boundary attachments beyond the first connecting weld to the pressure boundary, are not part of the pressure boundary. Therefore, they are not governed by the ASME B&PV Code. However, ASME B&PV Code Section III, Subsections NB and NF (Reference 1) were adopted as guidelines for performing the structural analysis of these components consistent with the current SG design basis analysis. Since these components are not required to meet ASME B&PV Code Class 1 standards they do not require a fatigue evaluation unless the range of stress intensities exceeds the elastic limits.

2.2.2.5.2.2.3 Description of Analyses and Evaluations

From a structural standpoint, the increased pressure and temperature variations specified in the revised design transients during EPU normal and upset operating conditions impact the SG. Both the primary and secondary side SG components are affected, resulting in an increase in stress intensity and fatigue usage factors. SG to balance of plant interface locations, such as at nozzles to pipe and external supports, are impacted by changes to the interface loads.

The EPU structural evaluation was performed by reconciling the existing SG design basis analyses against the revised design transient conditions and the revised interface loads. The scope of the reconciliation included all of the SG pressure boundary, as well as internal components. Specifically, reconciliations were performed for the tubesheet, stay-cylinder, U-tubes, primary head and vessel support skirt, secondary shell and internal/external attachments, primary and secondary nozzles, primary and secondary manways, handholes, inspection ports, studs and covers on all bolted openings, lattice grid and U-bend tube supports, shroud, and steam drum internals.

The reconciliation analyses used both classical and finite element methods to determine the stresses, stress intensity ranges, and fatigue usage factors for the EPU conditions. Classical methods included the use of prorating factors to multiply the results from the pre-EPU design basis analyses to approximate the corresponding stresses for EPU conditions. Since the range of stress occurring during a transient is related to the temperature and pressure variation during that transient, the change in the range of stress occurring during each postulated transient for the EPU relative to the design basis can be determined by taking the ratio of the new variation under the EPU conditions to the old variation and prorating the stress range results.

Prorating factor = $\Delta T'/\Delta T$ or $\Delta P'/\Delta P$

where: $\Delta T'$ is the temperature variation during the EPU transient
ΔT is the temperature variation during the design basis transient
$\Delta P'$ is the pressure (or pressure difference) variation during the EPU transient
ΔP is the pressure (or pressure difference) variation during the design basis transient

[ ]^{a,c}. The bounding ratio amongst these from each transient was used to conservatively prorate both the pressure and thermal stresses. Factors less than 1.0 were ignored since they were indicative that the existing analyses bounded the EPU conditions.

For some of the design transients, the EPU temperature histories were dissimilar enough from the pre-EPU temperatures to render the use of prorating factors inaccurate in the prediction of EPU stresses. In these instances detailed re-analysis by finite element methods was performed using ANSYS® 10 SP1.

Where finite element analysis was used, the calculated heat transfer coefficients and fluid temperature ramps for the Levels A and B transients were used as input to the finite element program to determine the metal temperature variation with time. The thermal analysis results were reviewed to determine the appropriate times during the transients for subsequent analysis of total and linearized stress levels. [The critical times were chosen by monitoring component-through-thickness-temperature differences, between components temperature differences, and skin temperature differences. The time-temperature histories of these differences were plotted, and the times at which they reached extremes were tabulated. These times formed the basis upon which subsequent analysis of total and linearized stress levels were performed. The temperature distribution and the corresponding pressure at each critical time were used to determine the pressure-plus-thermal loading stresses in static analyses]^{a,c}.

Linearized and total stress intensities were obtained through various sections of the models. Post-processing programs were used to calculate the linearized stress intensity range and fatigue usage factor at each selected location. Stress ranges and fatigue usage factors from the output of the finite element program ANSYS® were calculated in conformance with ASME Section III Subsection NB procedures. Stress intensity ranges and fatigue usage factors for perforated tubesheets with triangular pitch pattern were calculated from the output of the finite element program ANSYS® in conformance with ASME Section III Appendix A-8000 procedures.

Where the service loads on components were shown in the pre-EPU design basis analyses to satisfy the ASME rules for an exemption to fatigue analysis, the evaluations were repeated with the EPU loading to ensure that the exemption requirements remained satisfied. The rules for fatigue exemption place limitations on the number of full range pressure cycles, partial range pressure cycles, magnitude of thermal gradients within startup and shutdown cycles, magnitude of partial range thermal gradients during service and the magnitude of cyclic mechanical loads such as piping loads. For the most part, exemption provisions are based on conservative evaluations using allowable membrane stresses and the ASME fatigue design curves for the materials being considered.

All components, except for the pressure boundary bolted opening studs, were considered to operate at the EPU conditions for the original 40-year design life. A reduction in the number of design cycles was necessary only for the primary manway studs.

2.2.2.5.2.2.4 Results

The results from the structural evaluation are presented in LR Tables 2.2.2.5-3 and 2.2.2.5-4 for the primary and secondary side pressure boundary components respectively. LR Tables 2.2.2.5-3 and 2.2.2.5-4 list the stresses, stress intensities and fatigue usage factors for both pre-EPU conditions and EPU conditions for those components concluded to be significantly affected by the EPU. The internals are concluded to be largely unaffected by the EPU and are not included in the tables.

The results demonstrate that the SG pressure boundary and internal components continue to comply with the structural criteria of the ASME B&PV Code Section III Subsection NB and NF (Reference 1) for operation at the EPU conditions.

Relative to normal and upset conditions for the EPU, the stress intensity ranges in the majority of the SG pressure boundary remain unchanged, [ ]^{a,c}. The stress intensity ranges in the following secondary side components are concluded to remain unchanged under EPU conditions: [ ]^{a,c}. These components were shown to be exempt from a fatigue analysis in the pre-EPU analyses and it is concluded that they remain fatigue exempt under EPU loading. Since the stress intensity range and fatigue results are unchanged for these components for EPU conditions, no results are presented in LR Table 2.2.2.5-4.

For those components where the EPU conditions do produce higher stresses, slight increases in the stress intensity range of approximately [ ]^{a,c} when this new maximum stress is combined with the previous maximum stress occurring during **[**]^{a,c}. These increases are generally conservative since they represent locations where prorating factors are liberally applied to the entire stress intensity range even when this range is produced mainly by the **[**]^{a,c}. At several locations, larger increases in the stresses and stress intensity ranges of [ ]^{a,c} are found. These increases occur in the [ ]^{a,c} where detailed finite element analysis is used to completely re-qualify the components. A **[**]^{a,c} increase occurs at the **[**]^{a,c} where stresses are still small (i.e., [ ]^{a,c} ksi for EPU versus [ ]^{a,c} ksi for pre-EPU) and, thus, more sensitive to changes in the analytical procedure. [ ]^{a,c}. The resulting maximum membrane stress in the studs is [ ]^{a,c} lower for EPU but the maximum bending stress is [ ]^{a,c} higher.

Relative to normal and upset conditions for the EPU, the fatigue usage factors generally increase. Greater temperature and pressure variations result in greater alternating stresses and higher fatigue rates. Given that the allowable cycles on a fatigue curve are related to alternating stresses on a log basis, fatigue usage factors increase by a larger factor than for the stress intensity ranges discussed previously. Usage factors increase by as much as 190% under EPU conditions. The larger increase in usage factors reflects more conservative approaches used to derive the EPU results. **[**]^{a,c}. **[**]^{a,c}. [ ]^{a,c}. Decreases in the usage factors are also reported down to [ ]^{a,c} of the pre-EPU value. **[**]^{a,c}:

- [ ]^{a,c}.
- **[**]^{a,c}.
- **[**]^{a,c}.

Fatigue usage factors greater than 0.90 are indicative of more limiting areas within the SG pressure boundary. These areas consist of the [ ]^{a,c}. However, it is concluded that none of the usage factors that were greater than 0.90 for pre-EPU conditions change significantly under the EPU conditions. It is also concluded that no new usage factors are calculated to exceed 0.90 where they did not under pre-EPU conditions. The only exception to this is the **[**]^{a,c} where, instead of performing a reconciliation to determine the new usage factor under EPU conditions, the fatigue usage factor for the **[**]^{a,c} is used to conservatively represent the fatigue assessment at [ ]^{a,c}. High usage factors are typically the result of simple, conservative analyses from which the usage factors could be reduced through further, more sophisticated analysis. For example, the usage factors for **[**]^{a,c} are calculated using **[**]^{a,c}.

The impact of the EPU on the feedwater steady-state temperature is [ ][a,c].

A review of the maximum primary and secondary side temperatures and pressures specified for EPU conditions confirm that the temperature and pressure loading used for the design conditions **[**][a,c]. The emergency and faulted conditions thermal and pressure excursions are also [ ][a,c].
[ ][a,c].

Components affected by changes to interface loading are the primary nozzles, blowdown nozzles, main steam nozzle, feedwater nozzle, vessel support skirt, and internal pressure boundary attachments (shroud lugs, primary deck lugs and secondary deck lugs). Of these, only the **[**][a,c] are found to have increased interface loading under EPU conditions. The increase in loading is reconciled and new stresses presented in LR Tables 2.2.2.5-3 and 2.2.2.5-4 for design, normal, upset, emergency and faulted conditions that include stresses from increased interface loading.

The SG internals consist of the steam drum primary and secondary deck cyclones and components, feedwater header, shroud, lattice grid tube supports, and tube U-bend support assembly. [ ][a,c]. The loading of the internals occurs due to component dead weight, flow induced pressure differentials, thermal expansion, a burst steam or feed pipe, and a seismic event (OBE and SSE). The seismic, burst pipe and thermal expansion loading of the internals is **[**][a,c].

The U-tubes are exposed to the same loads as the SG internals. As discussed above, these loads are reconciled **[**][a,c].

Changes in the water film velocities and operating temperatures for the EPU operating conditions may affect the FAC rates. [ ][a,c]. Periodic inspection of the SGs is addressed in the Steam Generator Integrity Program.

The EPU associated changes in operating conditions will require the following:

- The number of design loading and unloading transient cycles required for 40 years of operation is 15,000 cycles. For the current operating parameters, only [ ][a,c] cycles could be met for the primary manway studs. As a result, the primary manway studs require replacement in **[**][a,c]. For EPU, the number of allowable cycles is further reduced to [ ][a,c] cycles requiring the studs to be replaced in **[**][a,c] years. This does not apply to the nuts which are qualified for the full 40-year design life.

The reduction in the operating life of the primary manway studs is caused by increases in the temperature and pressure variations of the design transients. This produces higher alternating stresses and a greater rate of fatigue over time. The transients that produce the most fatigue damage are **[**][a,c].

The remaining bolted openings [ ][a,c] where the ASME fatigue exemption rules remain satisfied. Therefore, there is no limitation to the design life for the constituent studs.

2.2.2.5.2.2.5 References

1. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB and NF and Appendices, (No Addenda), American Society of Mechanical Engineers, New York, 1986.

2. W. Kastner and K. Riedle, Empirical Model for the Calculation of Material Losses due to Corrosion Erosion, VGB Kraftwerkstechnik 86, December 1986.

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 ASME B&PV Code, 1986 Edition, No Addenda (Reference 1) limits pertaining to design of primary-to-secondary pressure differential drop (P) remain satisfied considering EPU SG design transients and EPU loading conditions.

2.2.2.5.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The specified design pressure limit for primary-to-secondary pressure differential is 2250 psi.

Acceptance Criteria

In accordance with Reference 1, the primary-to-secondary differential pressure for the normal and upset transient conditions is subject to the following design pressure requirements:

- Normal condition transients: Primary-to-secondary pressure gradient shall be less than the design limit of 2250 psi.
- 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. In other words, as long as the upset condition pressure values are less than 110 percent of the design pressure values, no additional analysis is necessary. 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 based on the EPU SG design transients. The pressure differentials across the primary-to-secondary-side pressure boundary under EPU 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 EPU 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 2.2.2.5-5. 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.

2.2.2.5.2.3.5 References

1. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, (No Addenda), American Society of Mechanical Engineers, New York, 1986.

2.2.2.5.2.4 Thermal-Hydraulic Performance

2.2.2.5.2.4.1 Introduction

Thermal-hydraulic analyses were performed for the SG at EPU conditions using the EPU licensed core rated power level of 3020 MWt (NSSS thermal power level of 3034 MWt). The analyses determined the SG thermal-hydraulic characteristics and inventories, and provided inputs used to evaluate the potential for tube wear, flow-induced vibration (FIV) failures, and potential tube fatigue damage. The results of this effort concluded that the SGs will continue to have satisfactory thermal-hydraulic performance for the EPU operating conditions. Detailed discussions regarding the evaluations and the conclusions reached are provided below.

2.2.2.5.2.4.2 Input Parameters, Assumptions and Acceptance Criteria

The EPU licensed core rated power level of 3020 MWt (NSSS thermal power level of 3034 MWt) was used in the analyses. All of the significant thermal-hydraulic input parameters are listed below. Performance was determined for both startup and end-of-life (EOL) conditions of the SGs.

The following describes the startup and EOL scenarios. The FIV and tube wear analysis is addressed in LR Section 2.2.2.5.2.5, Flow-induced Tube Vibration and Wear.

	Startup Conditions	End-of-Life Conditions
Tube plugging	0%	10%
Primary cold leg temperature	**[**]^{a,c}°F	[ ]^{a,c}°F
Primary inlet pressure	2250 psia	2250 psia
Steam nozzle pressure	[ ]^{a,c} psia	[ ]^{a,c} psia
Feedwater temperature	436.2°F	436.2°F
Primary flow rate per SG	[ ]^{a,c} gpm	[ ]^{a,c} gpm

A blow-down flow rate corresponding to **[**]^{a,c}% of steam flow was assumed in the analysis for all cases. This is the fraction blowdown for the benchmark case based on the mass flow. Steam carry-under, which is a linear function of the actual water level, was accounted for in the thermal-hydraulic calculations.

The tube fouling resistance was obtained by benchmarking the SG performance at a NSSS power level of 2701.4 MWt. Performance at EPU conditions is calculated by using the fouling factor determined by benchmarking to predict the steam nozzle pressure for both start-of-life and end-of-life conditions.

Water level corrections for the EPU conditions were performed to determine the actual water levels from the measured water levels. The actual water levels at full and part load power are used as inputs to the secondary side inventory calculation.

The following thermal-hydraulic acceptance criteria were adopted for the EPU conditions:

- moisture carry-over < [ ]^{a,c}% of steam flow
- two-phase stability ratio > **[**]^{a,c}

2.2.2.5.2.4.3 Description of Analyses and Evaluations

The thermal-hydraulic performance evaluation consisted of a steady-state heat balance using the one-dimensional nuclear code CIRC, as well as a full 3-D flow field analysis using the thermal hydraulic program ATHOSBWI. The thermal-hydraulic models developed for the original analysis of the Replacement SGs were utilized. The input conditions corresponding to the EPU conditions were as described above. All of the analyses were documented in the St. Lucie Nuclear Power Plant Unit 1 Replacement Steam Generators Extended Power Uprate Thermal-Hydraulic Performance Report.

FIV aspects are discussed in LR Section 2.2.2.5.2.5, Flow-induced Tube Vibration and Wear.

2.2.2.5.2.4.4 Results

LR Table 2.2.2.5-6 compares thermal-hydraulic attributes for startup at pre-EPU conditions, startup at EPU conditions, and end-of-life at EPU conditions. Based on the results of the thermal-hydraulic analyses performed and the associated results tabulated in LR Table 2.2.2.5-6, the SGs will continue to comply with the applicable design criteria for operation at the EPU conditions.

The secondary side pressure loss between feedwater inlet and steam outlet nozzles is expected to increase by approximately [ ]^{a,c} psi for EPU conditions. However, this is considered negligible when compared with the feedwater system pressure enveloped in the pre-EPU design analysis. The primary side pressure drop is expected to increase by about [ ]^{a,c} psi, other than coolant density effects, since the best-estimate primary coolant flow only increased by **[**]^{a,c}% for the EPU startup conditions. All the thermal-hydraulic parameters were within expected ranges for EPU conditions and for tube plugging up to 10%.

From moisture separator test results, the moisture carry-over of a separator increases with the amount of steam flow through it. From the separator performance curves, it was determined that with the increased steam flow associated with the EPU conditions, the moisture carry-over will remain well below the pre-EPU design limit of **[**]^{a,c}% of steam flow for operation at the EPU conditions.

The two-phase stability ratio for the current pre-EPU full power value is **[**]^{a,c}, which is well above the **[**]^{a,c} lower limit considered a conservative minimum for stable operations free of water level oscillations. The EPU 100% end-of-life full power stability ratio is [ ]^{a,c} and remains well above the acceptance criteria limit.

2.2.2.5.2.5 Flow-induced Tube Vibration and Wear

2.2.2.5.2.5.1 Introduction

FIV analysis and tube wear calculations were performed to demonstrate that the SGs tubes continue to be adequately supported to prevent detrimental FIV and fretting wear at the EPU conditions. It was demonstrated that the tubes are not susceptible to detrimental fluid-elastic instability (FEI) or vortex shedding resonance and that the accumulated tube wear over the life of the SGs is predicted to remain well below the established allowable wear limit for operation at EPU conditions.

2.2.2.5.2.5.2 Input Parameters, Assumptions, and Acceptance Criteria

The assessment of FIV and tube wear was performed at 100% power using the EPU licensed core rated power level of 3020 MWt (NSSS thermal power level of 3034 MWt) and 0% tube plugging. A tube wear calculation was also performed for the benchmarked case at an NSSS power level of 2701.4 MWt for comparison purposes.

The applicable EPU condition acceptance criteria are described below:

- critical FEI velocity ratio < 1.0 precluding fluid-elastic instability
- maximum vortex shedding resonance amplitude of [ ]^{a,c} mils ([ ]^{a,c}% tube OD)
- accumulated tube wear over 40-year life < 40% nominal tube wall thickness.

2.2.2.5.2.5.3 Description of Analyses and Evaluation

FIV and wear analysis of selected critical U-bend and bundle entrance tubes which exhibited the highest FIV responses prior to the implementation of the EPU are performed at EPU conditions. The critical tube in the U-bend region is tube [ ]^{a,c}, which has a U-bend radius of [ ]^{a,c} inches, two collector bar U-bend supports and two fan bar U-bend supports. The pre-EPU analysis showed that tube **[**]^{a,c} had a higher FEI ratio than tube **[**]^{a,c}. Tube **[**]^{a,c} is selected as the critical tube in the bundle entrance region since it had the worst FEI ratio and vortex shedding amplitude as presented in the results of the pre-EPU analysis. This analysis at EPU conditions considered the following FIV mechanisms:

a. Fluid-elastic instability,

b. Vortex shedding resonance, and

c. Random turbulence excitation (RT).

The methodology used to evaluate for fluid-elastic instability, vortex shedding resonance and random turbulence excitation for EPU conditions is the same as used in the pre-EPU analysis. For fluid-elastic instability, a conservative Conner's coefficient of [ ]^{a,c} is used to determine the critical gap cross-flow velocity, U_{cr}, below which experimental data shows that the tubes are stable. The effective gap velocity, U_{eff}, weighs the effect of the velocity distribution over the mode shape of vibration. The critical velocity ratio limit for fluid-elastic instability (FEI ratio) is defined as U_{eff}/U_{cr}. It is demonstrated that the FEI ratio for EPU conditions is less than one.

The St. Lucie Unit 1 SGs have stainless steel lattice bar tube supports that are not prone to accumulating magnetite deposits. Hence denting of tubes and/or crudding at the supports will not occur that might otherwise locally reduce the tube damping, increase the response to FIV and increase the tube mean stress.

When the vortex shedding frequency of fluid flowing past a tube is sufficiently close to the tube natural frequency, resonance can occur resulting in high amplitude vibrations. Vortex shedding resonance is only possible in single phase flow regions and two-phase flow regions with void fractions less than 15%, which limits this FIV mechanism to the bundle entrance region. Specifically, vortex shedding may only occur at the bundle entrance region for tubes near the bundle periphery and the tube-free-lane since the vortex sheet is prevented from forming further inside the bundle. The vortex shedding frequency is calculated using the Strouhal number which is a function of the tube pattern. Vortex shedding resonance is considered to occur when the vortex shedding frequency is within 30% of the tube natural frequency. When the potential for vortex shedding exists, the maximum amplitude of the resonating mode is demonstrated to be less than **[**]^{a,c}% of the tube outer diameter ([ ]^{a,c} mils). The **[**]^{a,c}% diameter limit is a traditional AECL guideline used by B&W Canada. Eddy current inspection data from other B&W SGs shows that almost all wear detected at support locations occurs in the U-bend region. Since tube wear due to vortex shedding would occur at the tube bundle inlet, and no excessive tube wear has been measured in this region, it can be concluded that vortex shedding is not an active degradation mechanism in B&W SGs.

Random turbulence excitation is a significant vibration excitation mechanism in typical liquid and two-phase cross-flow situations and causes continuous, small amplitude, broadband vibration. The turbulence-induced forces and the tube turbulent buffeting responses at any location along the tube length are evaluated by considering the mode shape, the mode natural frequency, the experimental bounding pressure power spectral density (PSD), the modal mass and the critical damping ratio. If the random turbulence excitation response of a tube is excessive it is an indication that the tube is not well supported and excessive tube wear is more likely to occur. The SGs have been designed with this in mind and have ample tube supports to ensure that flow induced vibration amplitudes are very small and tube cyclic stresses are negligible.

Tube wear calculations are performed for the U-bend region based on maximum random turbulence responses using Archard's equation (Reference 1). The tube wear is calculated in conformance to the latest published papers authored by industry experts (References 1 and 2). A work rate is determined from the integral average of the normal contact force multiplied by the sliding distance over the tube-to-support interface for each mode shape which is dissipated by support damping. This work rate is then converted into a wear volume and an equivalent wear depth based on wear coefficients for the tube and support materials and conservatively assuming wear occurs on one side of the tube only. The acceptable limit for tube wear over the 40-year design life of the SG is 40% of the nominal tube wall thickness in conformance with ASME B&PV Code Section XI and industry accepted guidelines.

The tube wear analysis accounts for fretting-wear. As part of this analysis, fretting wear is considered to occur continuously over the 40-year design life of the SG. The wear volume over the 40-year design is converted to a wear depth assuming [ ]^{a,c}.

Homogenous flow is considered for the FIV and wear analysis since this produces higher, more conservative mixture velocities for higher FEI ratios and random turbulence excitation results.

2.2.2.5.2.5.4 Results

The analytical results demonstrate that the SG tube bundles are adequately designed and supported for the FIV and tube wear that might occur over the 40-year design life with operation at the EPU conditions. This is supported by inspection results which show that tube wear at the current operating conditions is not an active degradation mechanism. At the end of operating cycle 21, the St. Lucie Unit 1 SGs had an operational time of 9.92 effective full power years (EFPY). Inspection results show a total of 24 wear indications at fan bar and tube supports in SG 1A and 7 wear indications in SG 1B.

The wear analysis for EPU conditions concludes that the tube wear will be approximately the same for EPU conditions as it was under pre-EPU conditions. Therefore, it is concluded that tube wear will not impact the safe operation of St. Lucie Unit 1 following implantation of the EPU.

The total riser flow for EPU and current conditions is approximately the same. However, the average steam quality in the U-bend region is about **[**]^{a,c}% higher for EPU conditions. This results in higher velocities for EPU conditions as the steam quality increases in the upward riser flow. Therefore the FIV and wear response in the U-bend region for EPU conditions is higher than for the non-EPU operating conditions.

For the EPU conditions, the maximum calculated critical velocity ratio for FEI in the U-tubes is **[**]^{a,c}, which satisfies the < 1.0 acceptance limit used for assessing FIV. The EPU calculated value compares to a maximum calculated ratio of **[**]^{a,c} for the benchmark case prior to EPU. The maximum vortex shedding resonance amplitude is **[**]^{a,c} mils which is well below the [ ]^{a,c} mils acceptance limit and is about the same as obtained for the benchmark case. The FIV calculated results are conservative since they are based on homogenous flow models which calculate higher flow velocities across the tubes.

Crudded tube supports behave in a similar manner to dented tube supports in that for both cases the tube becomes clamped at the tube support. The pre-EPU flow induced vibration analysis shows that with crudded supports the maximum FEI ratio is **[**]^{a,c}. Hence, even if this increases by **[**]^{a,c}% for EPU conditions the FEI ratio will still be less than 1.0. Therefore, fluid-elastic instability and failure by high-cycle fatigue will not occur.

The maximum expected tube wear at EPU conditions was also assessed. The results of this assessment demonstrated that over a 40-year operating life, the EPU did not significantly increase the maximum calculated tube wear as compared to the benchmark case prior to EPU. The maximum wear depth predicted for EPU conditions is [ ]^{a,c}% (percent wall thickness) for the U-bend region and [ ]^{a,c}% (percent wall thickness) for the bundle entrance region which is much less than the acceptance criterion of 40% through wall tube wear.

There have been no reports of tube fatigue in any B&W supplied re-circulating SGs. FIV analysis acceptance criteria are met for EPU conditions. The FIV criteria used for SG design limits random turbulence RMS displacement amplitudes to less than [ ]^{a,c} inches. By using this criterion, the tube bending stresses from the small random turbulence displacements will be less than the fatigue stress endurance limit. Also by ensuring the critical FEI velocity ratio is less than

1.0, FEI is precluded, which ensures large amplitude instabilities are prevented and tube fatigue will not occur.

2.2.2.5.2.5.5 References

1. Guerout, F.M. & Fisher, N.J., "Steam Generator Fretting Wear Damage: A Summary of Recent Findings," Proceedings ASME-PVP Symposium of FIV, 1999 Boston, USA, August 1-5, ASME Publication, Journal of Pressure Vessel Technology Vol. 121.
2. Pettigrew, M.J. & Taylor, C.E., "Vibration Analysis of Shell-and-Tube Heat Exchangers: An Overview - Part II: Vibration Response, Fretting-Wear, Guidelines," Journal of Fluids and Structures, Vol. 18, pgs. 485-500, 2003.

2.2.2.5.2.6 Tube Integrity

2.2.2.5.2.6.1 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 (Reference 1). In order for St. Lucie Unit 1 to adopt the provisions of the TSTF, FPL submitted a license amendment request to the NRC on April 24, 2006 (Reference 2), 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 l., Steam Generator Program.
- Add new TS 6.9.1.12, Steam Generator Tube Inspection Report.

On January 30, 2007, the NRC approved the requested changes to the St. Lucie Unit 1 TS (Reference 3).

2.2.2.5.2.6.2 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 at 3020 MWt (NSSS thermal power level of 3034 MWt). Loads in the U-bend region were calculated for seismic SSE, LOCA, and steam line break postulated events consistent with structural integrity performance criteria industry requirements. The main transient affecting accident tube loads under EPU conditions will be the LOCA, but the primary flow and temperature changes will not be significant and are bounded by the thermal hydraulic analysis previously performed for the pre-EPU design.

2.2.2.5.2.6.3 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 have considered both pressure and non-pressure loads for the pre-EPU design. A normal operating pressure differential (NOPD) of 1417 psi has been assumed in the current operational assessment, which is higher than the pre-EPU NPOD of 1365 psig. This NOPD is a conservative estimate for the EPU 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.

2.2.2.5.2.6.4 Results

Based on the reevaluation under EPU conditions, the SG tube accident loads which were previously qualified remain valid for EPU conditions except for full power NOPD across the tube wall. Full power NOPD for EPU is 1410 psi.

Given the above review, there is no impact to the current structural limits for St. Lucie Unit 1 given that,

- tube pressure differential used in the current operational assessment is 1417 psi which bounds the 1410 psi and,
- negligible change in non-pressure accident loads for EPU conditions compared with the pre-EPU design basis calculations.

2.2.2.5.2.6.5 References

1. Federal Register, 70 FR 24126, May 6, 2005.
2. Letter from Gordon L. Johnston (FPL), Proposed License Amendment Steam Generator Tube Integrity, to US Nuclear Regulatory Commission, April 24, 2006.
3. Letter from Brenda L. Mozafari (Nuclear Regulatory Commission), St. Lucie 1 – Issuance of Amendment Regarding Steam Generator Tube Integrity (TAC No. MD1382), to J. A. Stall (FPL), January 30, 2007.

2.2.2.5.2.7 Loose Parts and Foreign Objects

2.2.2.5.2.7.1 Introduction

Loose parts or foreign objects have been detected in both SG 1A and SG 1B over the history of operations of St. Lucie Unit 1. Detection has been accomplished via examinations required by TS and Nuclear Energy Institute (NEI) 97-06, Steam Generator Program Guidelines (Reference 1). Reasonable effort has been spent to remove all identified loose parts upon discovery.

The loose parts remaining in the SGs are documented, analyzed for future impact on SG tubes, and are added to a list of foreign objects to be actively tracked which are monitored during subsequent examinations. If inspections at two consecutive refueling outages indicate an object is no longer present, continued tracking 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. Currently there are no foreign objects in SG 1A or SG 1B which require tracking. At the end of cycle 21 there were no wear indications from foreign objects in SG 1A. Four new indications of foreign object wear affecting 3 tubes were newly reported in SG 1B.

For EPU conditions, an evaluation was performed to determine if the modified operating conditions would adversely affect the tube wear caused by possible future foreign objects.

2.2.2.5.2.7.2 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters and Assumptions

The current analysis considers:

- Previous loose part wear experience at St. Lucie and other B&W SGs.
- Secondary side thermal-hydraulic conditions for EPU conditions.

Major assumptions in the current analysis include:

- The SG tubes have been structurally qualified for a maximum allowable wear scar using the NEI 97-06 (Reference 1) performance criteria.
- All tubes with wear scars exceeding the repair criteria of 40% 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 tube eddy current inspections verify that this conservative value is not exceeded.
- The SGs are operating at EPU conditions.

Acceptance criteria

SG tube integrity shall remain consistent with the performance criteria of NEI 97-06, Rev. 2, Steam Generator Program Guidelines (Reference 1) at EPU conditions.

2.2.2.5.2.7.3 Description of Analyses and Evaluations

Secondary Side Loose Part 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 thermal-hydraulic characteristics relevant to loose part and foreign object induced tube wear. Wear is a function of drag force, object vibration and tube displacement. The drag force and displacements of the foreign object are a function of density and velocity (dynamic pressure).

Higher density and higher fluid velocities will result in a higher object induced tube wear. The saturated water density for the 100% full power EPU condition is slightly lower compared to the pre-EPU full power condition analyzed to benchmark the current operation of the plant. For the 100% full power EPU condition, the circulation ratio is lower than the benchmark condition. Hence, the velocity of the downcomer fluid, as it enters the tube bundle, is slightly lower than it is for the benchmark condition.

FIV and wear analysis performed for EPU and benchmark conditions show that there are no significant differences between critical FIV responses and calculated wear rates for bundle entrance tubes for both operating conditions. Therefore, the wear rates associated with foreign objects located at or just above the tubesheet are not expected to be any higher under EPU conditions as compared to the present benchmark conditions.

The total riser flow for EPU and benchmark conditions is approximately the same. However, the average steam quality in the U-bend region is about **[**]^{a,c}% higher for EPU conditions. This results in higher velocities for EPU conditions as the steam quality increases in the upward riser flow. The FIV and wear analysis of the critical U-bend tube for EPU and benchmark conditions show that the maximum fluid-elastic instability ratio increased by **[**]^{a,c}% for EPU conditions, considering velocity and density effects, although the predicted constant wear rate over the 40-year design life only increased by about [ ]^{a,c}%. There is no history of foreign objects in the SGs being transported up to, or near to the U-bend region, and it is unlikely that objects will be transported up to the U-bend region in the future. Consequently, this slight increase in loading under EPU conditions at significantly higher elevations above the tubesheet will have an insignificant effect on the potential for foreign object damage in the U-bend region relative to the present benchmark conditions.

In conclusion, the potential for tube wear due to foreign object damage is not increased due to EPU conditions because both the fluid density and the velocity of the recirculating water which enters the tube bundle is lower than it is currently. In the unlikely event that a foreign object is located in the U-bend region, the potential increase in predicted wear rate under EPU conditions is not considered significant.

Primary Side Loose Part Analysis

The Best-Estimate RCS flow rate was calculated for the 100% full power EPU condition. The volumetric flow rate and hence, the primary side velocity is slightly lower for the EPU condition as compared to the current plant condition. Hence, the potential for foreign object damage on the primary side does not increase due to operation at EPU conditions.

2.2.2.5.2.7.4 Results

For the secondary side loose parts analysis, condition monitoring and operational assessments have consistently documented past and future conformance of the SGs to the performance criteria of NEI 97-06. As noted in the analysis above, the changes in secondary and primary side flow do not adversely impact the potential for loose parts damage. All loose objects or foreign parts will be evaluated on a cycle-to-cycle basis to determine the acceptability of future operation.

2.2.2.5.2.7.5 References

1. NEI 97-06, Rev. 2, Steam Generator Program Guidelines, May 2005.

2.2.2.5.2.8 Tube Hardware

2.2.2.5.2.8.1 Introduction

Mechanical repair hardware refers to components such as plugs and stabilizers that are installed in SG tubes to address tube degradation. Tube plugging at St. Lucie Unit 1 is performed exclusively by using mechanical rolled plugs. These components were re-analyzed for the operating conditions specified in LR Section 1.1 and NSSS design transients in LR Section 2.2.6 associated with the EPU.

2.2.2.5.2.8.2 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters

Plant operating parameters at the licensed core rated power of 3020 MWt (NSSS thermal power level of 3034 MWt) are used to evaluate the mechanical rolled plugs (LR Section 1.1, Nuclear Steam Supply System Parameters).

The critical parameter affecting the design of the mechanical rolled plugs is the primary-to-secondary differential pressure in the SG. The current design differential pressure was shown to bound the normal/upset conditions for the EPU. Plug integrity was also evaluated at primary hydrostatic and secondary hydrostatic test pressures.

Acceptance Criteria

Mechanical Rolled Plugs

The SG hardware primary stresses due to design, normal, upset, emergency, faulted, and test conditions must remain within the allowable values of Reference 1. In addition to the stress criteria, retention of the mechanical rolled plug must be ensured.

Stabilizers

Stabilized tubes do not result in deleterious contact with adjacent tubes.

2.2.2.5.2.8.3 Description of Analyses and Evaluations

Mechanical Rolled Plugs

The enveloping condition for the mechanical rolled plugs is the one that results in the largest pressure differential between the primary and secondary side of the SG. Both the EPU NSSS parameter changes in LR Section 1.1 and the NSSS design transients in LR Section 2.2.6 were considered in determining the effect of the EPU on the mechanical plugs. The structural analysis and qualification of the plug considered loadings from all operating and accident transient conditions, including pressure, thermal expansion, hole dilation, deadweight, FIV, and seismic acceleration. The secondary side design pressure was conservatively neglected to maximize the stresses in the plug. Pre-EPU parameters used in the analysis bounded the EPU parameters of LR Section 1.1. A fatigue analysis for cyclic service was not required, since the NB-3222.4(d) requirements of Reference 1 were satisfied. Qualification tests confirm that the plugs fulfill the requirements of the ASME B&PV Code Section XI paragraph IWA-4713 for plugging and procedure qualification to repair heat exchanger tubing.

Stabilizers

At present there are no stabilizers installed in the SGs. However, if installation of a stabilizer is needed in the future, the EPU conditions will be considered in the qualification documentation for the design(s).

2.2.2.5.2.8.4 Results

Mechanical Rolled Plugs

The mechanical rolled plugs were evaluated for the EPU conditions. The parameters used in the pre-EPU analysis of the plugs bound the EPU parameters of LR Section 1.1. Therefore, the mechanical rolled plugs are acceptable for the EPU. The plugs have been qualified for a 40-year operating life.

The SG tube hardware components meet the stress/fatigue analysis requirements of the ASME B&PV Code, Section III for plant operation to support the EPU.

2.2.2.5.2.8.5 References

1. 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.

2.2.2.5.2.9 Steam Drum

2.2.2.5.2.9.1 Introduction

An evaluation was performed to assess potential degradation of steam drum components due to operation at EPU conditions.

2.2.2.5.2.9.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The assessment of the performance of the steam drum components considers the thermal-hydraulic conditions listed in LR Table 2.2.2.5-6 and SG operating experience.

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 or FIV of the steam separators.
- 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.
- Degradation will not create a loose part that will adversely impact or compromise the safe operation of the plant.

2.2.2.5.2.9.3 Description of Analyses and Evaluation

This evaluation of the impact of increased steam and increased feedwater flow at EPU conditions is based upon examining past inspection results of the steam drum components of SGs and a review of the corrosion allowances considered in the structural qualification of the SG components.

2.2.2.5.2.9.4 Results

The results of the evaluation performed to assess the potential for acoustic or FIV and/or FAC related degradation of the steam drum components in the SGs following implementation of EPU is discussed below.

Acoustic or Flow-Induced Vibration due to Increased Steam Flow

The SG primary separators are B&W second generation curved-arm primary (CAP-2) separators that are used in conjunction with B&W secondary cyclone separators; both of which are centrifugal type separators. The CAP-2 primary separators are relatively simple in design, consisting of a riser cylinder, [ ]^{a,c,d} sets of curved-arms, and a return cylinder. The primary separators are welded to the primary deck and are also welded together near the top of the separators to form a rigid structure which has a high natural frequency. The secondary separators are welded to the secondary deck to form compact, rigid structures. Due to their rigidity, neither assembly is susceptible to damaging flow induced vibration. The natural frequencies of both decks are outside the range of any flow pressure fluctuation and as a result no structural vibration is observed. The usual failure mechanism in a vibrating structure is fatigue failure which eventually leads to cracking. This condition has not been reported in any B&W Canada operating steam generators using separators of this or similar design.

The maximum steam flow per steam separator at EPU conditions for the St. Lucie Unit 1 SGs is [ ]^{a,b,c} lbm/hr. Exelon has implemented a 5% power uprate for both Braidwood Unit 1 and Byron Unit 1 with SGs that use CAP-3 steam separators, which are similar to the CAP-2 steam separators in the St. Lucie Unit 1 SGs. After the power uprate, the steam flow per CAP-3 steam separator at Braidwood is approximately [ ]^{a,b,c} lb/hr, which bounds the steam flow per separator for St. Lucie Unit 1. Exelon has not reported any changes in acoustic or FIV due to the increased steam flow following their EPU.

Acoustically induced vibration is not likely to happen in PWR steam generators producing saturated steam since this mechanism is primarily associated with vortex shedding resonance. It has been generally observed that vortex shedding resonance does not occur in two-phase flow regimes. In addition, the structural squeeze-film and viscous damping of the tube bundle will likely dissipate the energy needed to drive any acoustic standing waves which may be produced by a few acoustic vortices from a small percentage of tubes. Since the flow in the steam generator is highly inhomogeneous, only a few tubes are likely to generate acoustic vortices at the same frequency. Any vortex shedding "lock-in" is restricted to the peripheral tubes in the bundle entrance region and is not expected to impact the steam drum components. Vortex shedding has been shown to be well below the critical frequency ratio of [ ]^{a,c} (VS frequency/natural frequency) for steam drum components in B&W Canada steam generators of similar design supplied to other plants. Hence it is concluded that the St. Lucie Unit 1 SGs steam drum internals will not suffer acoustic or flow-induced vibration due to the increased steam flow at EPU conditions.

FAC Related Degradation

Feedwater flows are increased at EPU conditions. However, the feedwater header components in the SG are fabricated from [ ]^{a,c} material which has a combined chromium and molybdenum content of approximately [ ]^{a,c}%. Hence, the FAC rate is very low and the higher feedwater velocities due to EPU will have a negligible impact on the total FAC experienced by the feedwater system components during the design life of the SGs. Also, the feedwater system FAC rates in the pre-EPU analysis remain bounding because the higher feedwater temperature for EPU conditions reduces the FAC rate, offsetting the effect of higher feedwater velocities. To date, there have not been any reports of feedwater system FAC in any B&W SG.

The feedwater discharging from the J-tubes does not directly impinge on the shroud or any pressure boundary component as the discharge is oriented to flow into the space between the shroud and the feedwater header where the discharge flow is nearly parallel to the side of the shroud. There is a slight increase in the predicted FAC rate for the carbon steel shroud material due to increased feedwater flow; however, there is no impact on the shroud's structural integrity.

The FAC rate for carbon steel components in the downcomer increases by only [ ]^{a,c}%. The velocity in the downcomer depends on the circulation ratio which drops from [ ]^{a,c} to [ ]^{a,c} for EPU conditions, and this offsets other factors that would increase the velocity resulting in a small net downcomer velocity increase from [ ]^{a,c} ft/sec to [ ]^{a,c} ft/sec. Also, most SG material subject to FAC contains chromium which greatly reduces the FAC rate.

The [ ]^{a,c} has [ ]^{a,c} reactors, with [ ]^{a,c} SGs per reactor for a total of [ ]^{a,c} SGs. [ ]^{a,c}. The original [ ]^{a,c} primary steam separators installed at [ ]^{a,c} were fabricated using carbon steel material and needed to be replaced with new [ ]^{a,c} separators fabricated using stainless steel material due to perforations caused by FAC. Some limited FAC was also observed at the bottom of the [ ]^{a,c} carbon steel secondary cyclone separators. These secondary cyclone separators are similar in design to the secondary cyclone separators installed at St. Lucie Unit 1 and in the other B&W SGs. With the increased flow conditions within the steam drum expected from the EPU, there is the potential for material loss in the carbon steel primary and secondary cyclone steam separators. The operating experience at [ ]^{a,c} was that the degradation did not adversely impact or compromise the thermal performance or moisture separation function of the affected separators prior to replacement. The degradation also did not compromise the structural integrity of the affected separators, nor pose a risk of creating loose parts that would adversely impact or compromise the safe operation of the plant. The potential degradation in the separators is manageable through a standard inspection program that includes the SG secondary side internals. At St. Lucie Unit 1, continued monitoring of the primary and secondary steam separators by visual examination will be performed at regular intervals in conformance to NEI 97-06 (Reference 1).

To date, there have been no indications of perforations in any steam separator components in SGs in operation for many years at other plants including: Millstone 2, Ginna, Catawba 1, McGuire 1 & 2, St. Lucie 1, Byron 1, Braidwood 1, D. C. Cook 1, and Calvert Cliffs 1 and 2. Only minor FAC has been observed.

Loose Parts

The operating experience at **[**]^{a,c} was that the degradation did not compromise the structural integrity of the affected separators, nor pose a risk of creating loose parts that would adversely impact or compromise the safe operation of the plant.

The riser flow and re-circulated flow are slightly reduced for full-power EPU conditions as compared to current benchmarked conditions since the circulation ratio for current conditions is about **[**]^{a,c}% higher than EPU conditions and the steam flow for EPU conditions is about [ ]^{a,c}% higher than for current conditions. Considering the mean fluid density entering the primary separators will be about **[**]^{a,c}% lower for EPU conditions, the mean primary separator riser velocity will be over [ ]^{a,c}% higher than for current conditions. Also since the saturated liquid density is slightly lower for EPU conditions, the mean velocity of the re-circulated flow in the steam drum will be about [ ]^{a,c}% lower than it is for current benchmarked conditions. Despite this marginal increase in riser flow velocity inside the primary separators, the susceptibility to acoustic or FIV damage is not expected to increase since vortex shedding resonance is not a concern for steam drum internals.

Summary

An evaluation performed to assess potential degradation of steam drum components due to operation at EPU conditions concludes that there is little potential for acoustic or FIV and/or FAC related degradation of the steam drum components in the SGs.

2.2.2.5.2.9.5 References

1. NEI 97-06, Rev. 2, Steam Generator Program Guidelines, May 2005.

2.2.2.5.2.10 Chemistry

2.2.2.5.2.10.1 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 1 and 2). 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.

Uprates in power potentially affect water chemistry of the nuclear power plant because of changes in temperature and/or flow rates.

2.2.2.5.2.10.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The following represents the input parameters and assumptions used in support of the evaluation.

- The input parameters provided in LR Section 1.1, EPRI primary and secondary chemistry guidelines (Reference 1 and 2), and strategic water chemistry plans for the primary and secondary sides as embodied in the Steam Generator Integrity Program.
- St. Lucie Unit 1 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 uprating because the chemistry will continue to be controlled after the uprate by plant procedures and specifications conforming to industry accepted guidelines as embodied in the Steam Generator Integrity Program.

2.2.2.5.2.10.3 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 1.

2.2.2.5.2.10.4 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 after the EPU by plant procedures and specifications conforming to industry accepted guidelines and embodied in the St. Lucie Unit 1 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.

2.2.2.5.2.10.5 References

1. EPRI PWR, Primary Water Chemistry Guidelines Vol. 1 and 2, Rev. 6.
2. EPRI PWR, Secondary Water Chemistry Guideline 1008224, Rev. 7.

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, GDCs -1, -2, -4, -14, and -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.

Table 2.2.2.5-1
Comparison of Pre-Uprate and EPU Loads
Steam Generator Lower Support Reactions

Load	Pre-Uprate Load (kips)		EPU Load (kips)	
	Deadweight	Thermal + Deadweight	Deadweight	Thermal + Deadweight
Y1	300	0	265	0
Y2	300	315	569	104
Y3	300	1009	573	862
Y4	300	320	359	102
μY	375	300	172	259

Table 2.2.2.5-2
NOP Steam Generator Sliding Base Plate (SBP) Gaps

SG1A	Lift-off (in)
Y1	0.037
SG1B	
Y1	0.085
Y2	0.019
Y4	0.019

Table 2.2.2.5-3
EPU Evaluation Summary
Critical Locations of Primary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi)	EPU Stress (ksi)	Allowable Stress (ksi)
			Fatigue	Fatigue	Allow. Fatigue
Primary-inlet nozzle-to-shell juncture	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Primary inlet nozzle within limit of reinforcement	Design	Pm PL PL + Pb	[ ] a,c	[ ] a,c	26.7 40.05 40.05
Primary inlet nozzle safe end	Design	Pm PL + Pb	[ ] a,c	[ ] a,c	17.4 26.1
Primary head at inlet nozzle	Design	Pm PL PL + Pb	[ ] a,c	[ ] a,c	26.7 40.05 40.05
Primary inlet nozzle within limit of reinforcement	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	43.8 39.4 65.7 65.7
Primary inlet nozzle outside limit of reinforcement	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	26.6 23.9 39.9 39.9
Primary head at inlet nozzle	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	43.8 39.4 65.7 65.7
Primary inlet nozzle within limit of reinforcement	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	56.0 84.0 84.0
Primary inlet nozzle outside limit of reinforcement	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	49.0 73.5 73.5
Primary head at inlet nozzle	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	56.0 84.0 84.0

Table 2.2.2.5-3 (Continued)
EPU Evaluation Summary
Critical Locations of Primary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi) Fatigue	EPU Stress (ksi) Fatigue	Allowable Stress (ksi) Allow. Fatigue
Primary head/inlet nozzle dam ring juncture	Normal/Upset	Fatigue	[ ] a,c	[ ] a,c	1.0
Primary-outlet nozzle-to-shell juncture	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Primary outlet nozzle within limit of reinforcement	Design	Pm PL PL + Pb	[ ] a,c	[ ] a,c	26.7 40.05 40.05
Primary outlet nozzle safe end	Design	Pm PL + Pb	[ ] a,c	[ ] a,c	17.4 26.1
Primary Head At Outlet Nozzle	Design	Pm PL PL + Pb	[ ] a,c	[ ] a,c	26.7 40.05 40.05
Primary outlet nozzle within limit of reinforcement	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	43.8 39.4 65.7 65.7
Primary outlet nozzle outside limit of reinforcement	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	26.6 23.9 39.9 39.9
Primary head at outlet nozzle	Emergency	Pm Pm (pressure) PL PL + Pb	[ ] a,c	[ ] a,c	43.8 39.4 65.7 65.7
Primary outlet nozzle within limit of reinforcement	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	56.0 84.0 84.0
Primary outlet nozzle outside limit of reinforcement	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	49.0 73.5 73.5

Table 2.2.2.5-3 (Continued)
EPU Evaluation Summary
Critical Locations of Primary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi) Fatigue	EPU Stress (ksi) Fatigue	Allowable Stress (ksi) Allow. Fatigue
Primary head at outlet nozzle	Faulted	Pm PL PL + Pb	[ ] a,c	[ ] a,c	56.0 84.0 84.0
Primary head/outlet nozzle dam ring juncture	Normal/Upset	Fatigue	[ ] a,c	[ ] a,c	1.0
Primary head/tubesheet juncture	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Stay cylinder/ tubesheet juncture	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Stay cylinder cap	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Tubesheet perforated region Nominal ligament	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Tubesheet perforated region Thin ligament (secondary side)	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Tubesheet perforated region NR ligament	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Tubesheet rim	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Tubesheet dome	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Primary head at divider plate seat bar	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0

Table 2.2.2.5-3 (Continued)
EPU Evaluation Summary
Critical Locations of Primary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi) Fatigue	EPU Stress (ksi) Fatigue	Allowable Stress (ksi) Allow. Fatigue
Primary head adjacent to support skirt	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Main vertical support skirt	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Instrument taps	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Accelerator taps	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Primary manway at shell	Normal/Upset	Pm + Pb + Q Fatigue	[ ] a,c	[ ] a,c	80.1 1.0
Primary manway studs	Normal/Upset	σ_{ave} σ_{max} Fatigue	[ ] a,c	[ ] a,c	56.6 80.2 1.0
The stress and/or fatigue results for the EPU conditions might be lower than those for pre-EPU. This is due to a change in methodology or the removal of conservatisms during the EPU analytical reconciliation and does not invalidate the pre-EPU result.					

Table 2.2.2.5-4
EPU Evaluation Summary
Critical Locations of Secondary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi) / Fatigue	EPU Stress (ksi) / Fatigue	Allow. Stress (ksi) / Allow. Fatigue
Secondary shell/tubesheet juncture	Normal/Upset	Pm + Pb + Q Fatigue	52.2 0.17	[ ]a,c	[ ]a,c
Secondary deck lugs	Design	Pm PL PL + Pb	0.1 0.1 2.1	[ ]a,c	[ ]a,c
Secondary deck lugs at shell	Design	Pm PL PL + Pb	17.8 17.9 19.8	[ ]a,c	[ ]a,c
Secondary deck lugs	Normal/Upset	Pm + Pb + Q Fatigue	40.6 exempt	[ ]a,c	[ ]a,c
Secondary deck lugs	Emergency	Pm PL PL + Pb	16.4 16.6 19.7	[ ]a,c	[ ]a,c
Secondary deck lugs	Faulted	Pm PL PL + Pb	16.4 16.6 27.7	[ ]a,c	[ ]a,c
Feedwater nozzle forging and shell	Normal/Upset	Pm + Pb + Q Fatigue	79.9 0.80	[ ]a,c	[ ]a,c
Feedwater nozzle transition/ extension ring	Normal/Upset	Pm + Pb + Q Fatigue	69.2 0.80	[ ]a,c	[ ]a,c
Feedwater nozzle safe end	Normal/Upset	Pm + Pb + Q Fatigue	52.1 0.82	[ ]a,c	[ ]a,c
Main steam nozzle within limit of reinforcement	Design	Pm PL	4.8 12.5	[ ]a,c	[ ]a,c
Main steam nozzle safe end	Design	Pm PL	16.0 18.3	[ ]a,c	[ ]a,c
Main steam nozzle safe end	Normal/Upset	Pm + Pb + Q Fatigue	25.3 Exempt	[ ]a,c	[ ]a,c

Table 2.2.2.5-4 (Continued)
EPU Evaluation Summary
Critical Locations of Secondary Side Pressure Boundary Components

Component	Load Condition	Stress Category	Pre-EPU Stress (ksi) / Fatigue	EPU Stress (ksi) / Fatigue	Allow. Stress (ksi) / Allow. Fatigue
Main steam nozzle/head juncture	Normal/Upset	Pm + Pb + Q Fatigue	34.3 Exempt	[ ]a,c	[ ]a,c
Secondary head/shell juncture	Normal/Upset	Pm + Pb + Q Fatigue	36.8 Exempt	[ ]a,c	[ ]a,c
Main steam nozzle outside of limit of reinforcement	Emergency	Pm PL PL + Pb	13.6 13.7 13.7	[ ]a,c	[ ]a,c
Main steam nozzle within limit of reinforcement	Emergency	Pm PL PL + Pb	4.2 13.9 13.9	[ ]a,c	[ ]a,c
Secondary head at main steam nozzle (bounds all other locations on head)	Emergency	Pm PL PL + Pb	17.1 19.7 19.7	[ ]a,c	[ ]a,c
The stress and/or fatigue results for the EPU conditions might be lower than those for pre-EPU. This is due to a change in methodology or the removal of conservatisms during the EPU analytical reconciliation and does not invalidate the pre-EPU result.					

Table 2.2.2.5-5
Summary of Design Pressure Differential (∆P) for EPU

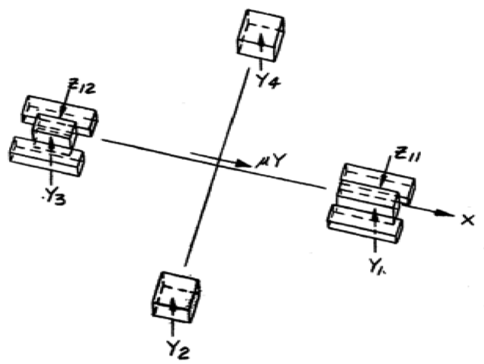
Load Condition	Limiting Transient	∆P (psi)	Allowable (psi)
Normal	Step load increase	1529	2250
Upset	Loss of RCS flow	1450	2475

Table 2.2.2.5-6
EPU Evaluation Summary
Thermal-Hydraulic Results

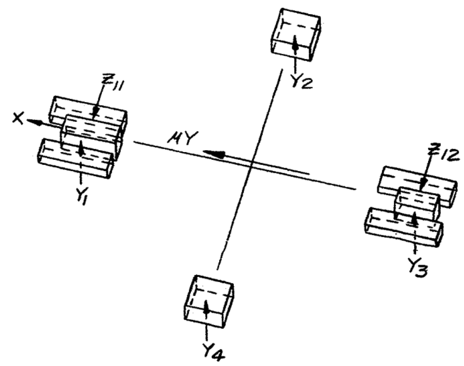
Thermal-hydraulic Attribute		Startup for Pre-EPU Conditions	Startup for EPU Conditions	End-of-Life for EPU Conditions
Power [MWt] (Total for 2 SGs)		2710	3034	3034
Plugging [%]		0	0	10
Temperatures [°F]	Feedwater	435	436.2	436.2
	Primary inlet	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
	Primary outlet	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
Pressures [psia]	Steam nozzle	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
Flow rates [10^6 lbm/hr] per SG	Steam	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}
	Primary fluid	[ ]^{a,c}	[ ]^{a,c}	[ ]^{a,c}

a. NSSS thermal power level.

Figure 2.2.2.5-1
Steam Generator Lower Support Reactions



SG1A



SG1B

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 EPU. The RCPs are described in UFSAR Sections 3.9, 5.1, and 5.5.5. The RCP supports are described in UFSAR Section 5.5.7.2. Each of the two reactor coolant loops contains two vertically mounted, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The regulatory evaluation included in LR Section 2.2.2, Pressure-Retaining Components and Component Supports also applies to the RCPs and associated supports.

The functions of the RCPs 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 coast down to prevent core damage in the event of a simultaneous loss of power to all RCPs.
- To provide a portion of the reactor coolant pressure boundary (RCPB).

The technical evaluation, included as part of this licensing report (LR) subsection, describes the input parameters, assumptions and acceptance criteria used to evaluate the structural integrity of the RCPs and associated supports for EPU conditions. Even though all functions of the RCPs are defined above, the scope of this technical evaluation is limited to determining by analysis and/or evaluation that the RCP portion of the pressure boundary has been maintained for EPU.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis in LR Section 2.2.2, Pressure-Retaining Components and Component Supports, applies to the RCPs and their supports, with the following amplifications.

The RCPs which circulate the reactor coolant through the RCS are designed to:

a. Circulate reactor coolant with the chemistry identified in UFSAR Table 9.3-8 at the flows listed in UFSAR Table 5.5-9.

b. Meet the requirements of ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Class A, Winter 1967 Addenda.

c. Meet the transient operating condition categories listed in UFSAR Section 5.2.1.2.

d. Provide sufficient moment of inertia to reduce the flow decay through the core upon loss of RCP power.

e. Prevent reverse rotation of the RCP upon loss of pump power with the other RCPs operating.

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal motor driven pumps as shown in UFSAR Figure 5.5-6. The design parameters for the pumps are given in UFSAR Table 5.5-9.

UFSAR Section 3.2 and Table 3.2-1 provide seismic classification, quality group, tornado wind criterion, flood criterion, missile criterion, and applicable ASME B&PV Code category for structures, systems, and components (SSCs), including the RCPs and associated piping.

The RCPs are designed to the requirements of ASME B&PV Code Section III, Nuclear Vessels, Class A, 1965 edition through the Winter of 1967 Addenda supplemented by the requirements given in UFSAR Table 5.2-2A.

The major components of the RCS are designed to withstand the forces associated with postulated pipe ruptures, in combination with the forces associated with the design basis earthquake and normal operating conditions.

The RCP and motor assembly are supported by spring hangers attached to the four support lugs welded to the pump case. The spring hangers permit motion in the horizontal and vertical direction to compensate for thermal and seismic movement. 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 5.2.1.

The flywheels are inspected periodically as part of the inservice inspection program. The RCP motor flywheel assembly and inspection ports are shown on UFSAR Figure 5.5-11.

In-service inspection is performed in accordance with the guidelines of NRC Regulatory Guide 1.14, *Reactor Coolant Pump Flywheel Integrity,* Revision 1, August 1975.

In addition to the licensing basis described in the UFSAR, the RCPs and supports were evaluated for St. Lucie Unit 1 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 breaks (BLPB) analysis results are combined in accordance with the UFSAR 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 major inputs used in the RCP evaluation are the EPU parameters provided in LR Section 1.1, Nuclear Steam Supply System 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. For design load 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 SAR 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 B&PV 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 (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 B&PV 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 these EPU-driven temperature changes were considered in the RCP evaluation.

Design Transients

The evaluation of the RCPs and RCP supports for the EPU compared the operating temperatures, operating pressures and NSSS design transients defined in the EPU parameters (LR Section 1.1) to those inputs considered in the analyses of record (AORs) for the RCPs. The impact of changes in 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 stresses and fatigue. Therefore, no additional transient analyses were required to evaluate the RCPs 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, Nuclear Steam Supply System Piping, Components 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 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 pre-EPU 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., Youngs modulus) controlling the stiffness, and therefore, on 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 condition load changes due to the EPU were addressed by simple evaluations which took advantage of the fact that the design basis loads are as-calculated loads with margin added. Any minor changes in seismic and pipe break loads derived from re-analyses are enveloped by the existing design loads.

The Best-Estimate performance parameter analysis for the EPU determined a maximum required flow rate of 203,483 gpm per loop. The design flow rate is equal to the largest Best-Estimate 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 the vertical 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 operation condition, as shown in 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 kips vertical load 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 kips $\times$ 0.667 = 53.3 kips.

In all cases, the EPU loads are either bounded by the original design or are less than the equivalent design load for normal operating conditions. The evaluation concludes that there is no adverse effect on the ability of RCP support to operate at the EPU conditions.

2.2.2.6.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the RCPs and supports is 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 design basis 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 Best-Estimate performance parameters under EPU conditions, have concluded that the flow rate to which the pumps were designed (203,483 gpm per loop) is equal to the largest Best-Estimate flow rate for the EPU. Since the RCPs can maintain the largest estimated flow rate under EPU conditions, they will also continue to operate in a manner which satisfies requirements a) through e) stated 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. The results demonstrate that the normal operating loads on these hangers remain below the allowables.

2.2.2.6.3 Conclusion

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, 1965 Edition, including Addenda through Winter of 1967.

Table 2.2.2.6-1
RCP Normal Operating Spring Hanger Loads

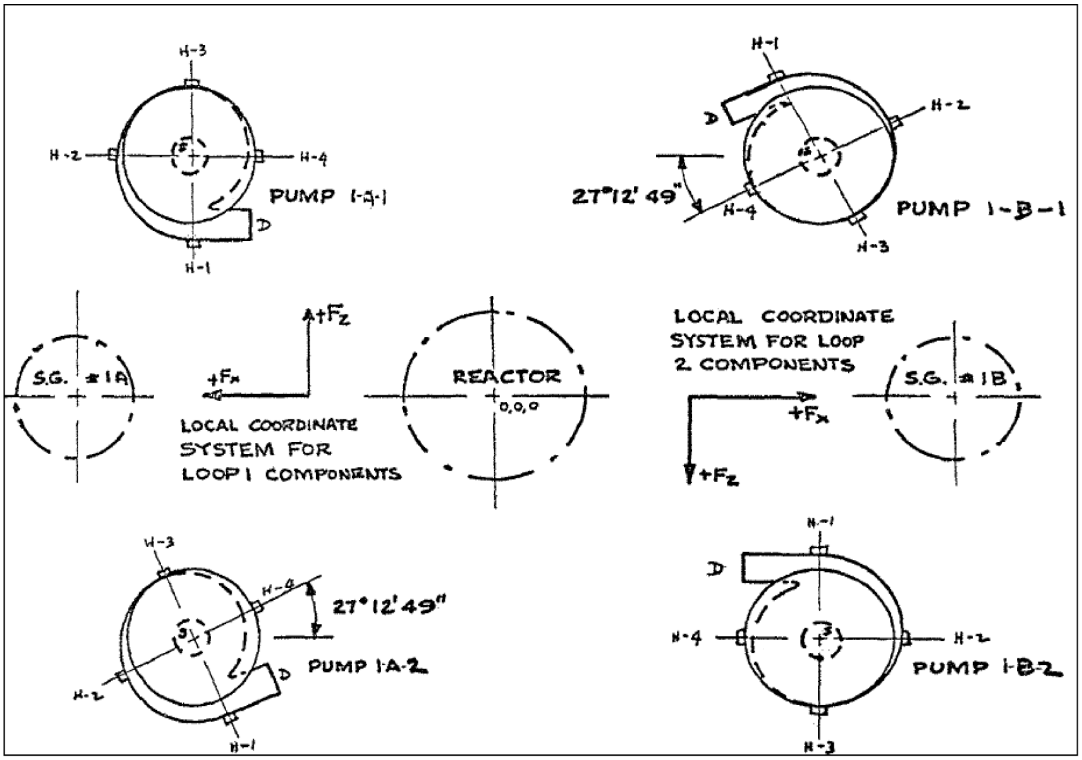
Condition	Hanger #	Axial Loads on RCP Spring Hangers		
		Allowable (each hanger) kips	EPU Condition	
			RCPs 1A2 and 1B1 kips	RCPs 1A1 and 1B2 kips

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	
1A1	H-1	25.6	47.0	21.4	(3)
	H-2	58.2	62.0	3.8	(1)
	H-3	69.7	59.0	-10.7	
	H-4	42.6	52.0	9.4	(2)
1A2	H-1	63.2	54.0	-9.2	
	H-2	63.8	60.0	-3.8	
	H-3	34.6	64.0	29.4	(1)
	H-4	35.0	39.0	4.0	(1)
1B1	H-1	63.2	54.0	-9.2	
	H-2	63.8	60.0	-3.8	
	H-3	34.6	64.0	29.4	(1)
	H-4	35.0	39.0	4.0	(1)
1B2	H-1	25.6	47.0	21.4	(1)
	H-2	58.2	62.0	3.8	(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*0.6 fy/0/9fy = 53.3 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 is a cylindrical carbon steel vessel with stainless steel clad internal surfaces. The pressurizer is supported by a cylindrical skirt welded to the bottom head. The skirt is designed to withstand dead weight and normal operating loads as well as the loads due to earthquakes and LOCA.

The pressurizer provides a point in the reactor coolant system (RCS) where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure and level control purposes. A spray nozzle on the top head is used in conjunction with heaters in the bottom head to provide level and pressure control. The spray is supplied from the B loop reactor coolant pump (RCP) cold legs and discharges to the pressurizer spray nozzle. Automatic spray control valves control the amount of spray as a function of pressurizer pressure. The pressurizer heaters are single unit, direct immersion heaters which protrude vertically into the pressurizer through sleeves welded in the lower head. Each heater is internally restrained from high amplitude vibrations and can be individually removed for maintenance during plant shutdown.

Overpressure protection is provided by three pressurizer safety valves (SRVs) and two power operated relief valves (PORVs). In the event of an abnormal transient that causes a sustained increase in pressurizer pressure at a rate exceeding the control capacity of the spray, a high pressure trip setpoint will be reached. This signal trips the reactor and opens the two power operated relief valves. The steam discharge by the relief valves goes to the quench tank where it is condensed (see LR Section 2.5.2, Pressurizer Relief Tank). A surge line connects the pressurizer to the reactor coolant piping in loop 1B hot leg.

Pressure is maintained by controlling the temperature of the saturated liquid volume in the pressurizer. At full load conditions, slightly more than one half the pressurizer volume is occupied by saturated water, and the remainder by saturated steam. In order to maintain pressure, the corresponding saturation temperature must be maintained. To maintain this temperature approximately 20% of the installed heaters are kept energized to compensate for heat losses through the vessel and to raise the continuous subcooled pressurizer spray flow to the saturation temperature. The water level in the pressurizer is programmed as a function of average coolant temperature.

St. Lucie Unit 1 Current Licensing Basis

The generic current licensing basis in LR Section 2.2.2 applies to the pressurizer and its supports, with the following amplifications:

As a result of increased susceptibility to primary water stress corrosion cracking (PWSCC) of alloy 600 and comparable weld material, the original St. Lucie Unit 1 pressurizer was replaced. The replacement pressurizer was designed, fabricated, and analyzed as a direct replacement for the original pressurizer. A comparison of the original pressurizer and the replacement pressurizer design data is presented in UFSAR Table 15.1.8-1. This table illustrates the physical and thermal-hydraulic similarity between the replacement and original designs. The replacement pressurizer is classified as Seismic Category I and was designed and fabricated in accordance with the ASME Section III, 1998 Edition through 2000 Addenda. Section 15.1.8 of the UFSAR provides additional detail regarding the replacement pressurizer.

For the remainder of this LR section, the replacement pressurizer will be referred to as the pressurizer.

UFSAR Section 5.5.2.1 describes the design bases for the pressurizer. As described in UFSAR Section 5.5.2.3, it was shown by analysis made in accordance with the requirements for Section III Class A vessels that the pressurizer is adequate for normal operating and transient conditions expected during the life of the plant.

UFSAR Section 5.2.1.2 discusses the transients used in the design and fatigue analyses for the pressurizer. Fatigue analyses were performed in accordance with the applicable ASME codes. As stated in UFSAR Section 5.2.1.2, it was demonstrated that the maximum stress intensities and cumulative usage factors are in compliance with code values. The design basis cyclic transients were revisited for the pressurizer surge line and nozzles to address thermal stratification and thermal striping concerns raised by NRC Bulletin 88-11. The analysis developed a new set of design basis transients based on collected data.

The pressurizer is tested per the requirements of Section III of the ASME Code and inspected per the requirements of Section XI of the ASME Code in accordance with Technical Specification 4.0.5.

In addition to the licensing basis described in the UFSAR, the pressurizer and supports were evaluated for St. Lucie Unit 1 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 analysis was a review of current component and nuclear steam supply system (NSSS) parameters evaluated in the pre-EPU design analysis for the replacement pressurizer, the UFSAR, NUREG-1179, and various calculations and documents. Parameters reviewed included temperature, design transients, and pressure. The EPU conditions were then factored into this analysis to determine their impact. 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.

Any impact of EPU on the pressurizer would result from the temperature effects associated with increasing the NSSS design thermal power level from 2714 MWt to 3034 MWt with an associated increase in RCS average temperature from 571.3°F to 578.5°F. However, 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 its supports.

2.2.2.7.2.2 Input Parameters, Assumptions and Acceptance Criteria

Design inputs for the pre-EPU equipment were compared with the EPU design inputs in LR Section 1.1, Nuclear Steam Supply System Parameters and LR Section 2.2.6, NSSS Design Transients. 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 parameters and design transients in LR Section 1.1, Nuclear Steam Supply System Parameters and LR Section 2.2.6, NSSS Design Transients showed that the changes in RCS hot leg (T_{hot}) and cold leg (T_{cold}) were enveloped by the original equipment specification. 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.

Horizontal loads, and moments caused by horizontal loads, are taken by the concrete shield walls. Since horizontal loads and moments are not changing under EPU conditions, concrete shield wall loading associated with the EPU is bounded by current analysis.

The foundation is analyzed for vertical loads only. The design vertical load is 1.5×305.3 or 458k. Proper anchorage and reinforcement are provided to transfer loads into base concrete. The information on modeling and analysis for the pressurizer is found in UFSAR Sections 3.7.3.2.2(b) and 3.7.3.2.3. As EPU will not change vertical load, current evaluations bound 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 when operating at a pressure of 2485 psig at a temperature of 700°F. The stress from pressure calculation was performed and analyzed against EPU conditions. As EPU conditions do not significantly change these values for the spray nozzle stress analysis and, since the pressurizer has a design pressure of 2500 psia, the results of this analysis for the pre-EPU spray line nozzle stresses bound those for the post-EPU spray line nozzle stresses.

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 SRV and PORV piping was evaluated for EPU conditions; see LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports. Based on the analysis, it was determined that the maximum loads in the piping segments connected to the PORV and SRV nozzles are bounded by the original design, thus the nozzle loads are also bounded by the original design.

Current pressurizer instrument nozzle loads will continue to be valid after EPU implementation since the operating and design pressure and temperature conditions for the pressurizer are not affected by the EPU.

The operating thermal loads are defined by the thermal transient conditions as contained in LR Section 2.2.6. Thermal analyses for the pressurizer spray line nozzle were performed. The transients tested were heat up and cool down, plant loading and unloading, step load increase and decrease, normal variations, reactor trip and loss of primary flow, loss of load, and leak test up and down. The thermal expansion analysis was evaluated for the design temperature of 700°F whereas the operating temperature is 653°F. The analysis was conservative and is unaffected by EPU. EPU conditions are bounded by the parameters given in the analyses and, therefore, are not affected.

10 CFR 50, Appendix G, *Fracture Toughness Requirements* was analyzed for EPU conditions and no changes were found. The flaw evaluations were first performed to show that postulated flaws, with depths equal to one-quarter of the wall thickness, satisfy the 10 CFR 50, Appendix G, KIR fracture toughness requirements considering safety factors of two on pressure and one on thermal loads. The analysis concluded that the 10 CFR 50, Appendix G fracture toughness requirements will be met under EPU conditions as there are no transients involved.

Pressurizer transients are listed in the Engineering Specification for the Replacement Pressurizer Assembly and were evaluated for EPU conditions. The evaluations pre-EPU 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 is bounded by existing evaluations.

Analysis of flow induced vibration is included in the transient conditions evaluation. This degradation mechanism is not considered to be a concern for the pressurizer because the components are subject to relatively low fluid flow velocities. However, vibratory excitation is discussed in the equipment 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 RCP. 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 Evaluation of 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 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.

2.2.2.7.2.5 Results

FPL has reviewed the functional design of the pressurizer and its 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 RCS and calculations updated. 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.

2.2.2.7.3 Conclusion

FPL has reviewed the structural integrity of the pressurizer and its supports. For the reasons set forth above, FPL concludes that the review has adequately addressed the effects of the proposed EPU on the pressurizer and its supports. Based on the above, FPL further concludes that the review has demonstrated that the pressurizer and its 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 pressurizer and its supports.

2.2.2.8 Conclusions for Pressure-Retaining Components and Component Supports

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 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.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

2.2.3.1 Regulatory Evaluation

Reactor pressure vessel internals (RPV) consist of all the structural and mechanical elements inside the reactor vessel, including core support structures. FPL reviewed the effects of the 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.
- 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 acceptance criteria are based on:

- 10 CFR 50.55a 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-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance is provided in Matrix 2 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 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.

All 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 1. 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. 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, 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 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 design basis earthquake (DBE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a LOCA coincident with the effects of the DBE. 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 DBE.

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.

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, 3.7.5 and 3.11 for details.

- 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-N 18.2, 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. These 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 an adequate protective system. (refer to UFSAR Section 7.2 and Chapter 15)

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (Limiting Conditions for Operations) which support Chapters 4 and 15 of the UFSAR. The plant is designed such that operation within Limiting Conditions for Operation (LCO), 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 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 non-accident conditions.

The RVI are designed to meet the loading conditions listed in UFSAR Section 4.2.2.1.1 and the design limits specified in UFSAR Section 4.2.2.1.2.

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 not greater than those given in the May 1972 draft of Section III of the ASME Code, Subsection NG, Appendix F, *Rules for Evaluation of Faulted Conditions.* Stress limits for the reactor vessel core support structures are presented in UFSAR Table 4.2-4. In the design of reactor vessel internal components which are subject to fatigue, the stress analysis is performed utilizing the design fatigue curve of Figure 1-9-2 of Section III of the ASME Code and a CUF of less than 1.0 as the limiting criteria. In addition, to properly perform their functions, the reactor internal structures will satisfy the deformation limits listed below.

a. Under design loadings plus operating basis earthquake forces or normal operating loadings plus design basis earthquake forces, deflections will be limited so that the control element assemblies (CEAs) can function and adequate core cooling is preserved.

b. Under normal operating loadings plus design basis earthquake forces plus pipe rupture loadings resulting from a break of the largest line connected to the reactor coolant system (RCS) piping, deflections will be limited so that the core will be held in place, adequate core cooling is preserved, and all CEAs can be inserted. Those deflections which would influence CEA movement will be limited to less than 80 percent of the deflections required to prevent CEA insertion.

c. Under normal operating loadings plus DBE forces plus the maximum pipe rupture loadings resulting from the full spectrum of pipe breaks, deflections will be limited so that the core will be held in place and adequate core cooling is preserved. Although CEA insertion is not required for the largest RCS pipe break, calculations show that the CEAs can be insertable except for a few CEAs located near the vessel outlet nozzle which is feeding the postulated break.

During the end of the Unit 1 Cycle 5 refueling outage, difficulties were encountered during core reload when a fuel assembly would not seat properly on the core support plate. Subsequent inspection determined there was debris of unknown origin on the plate. The fuel was unloaded and the core support barrel (CSB) was removed to investigate the source of the debris. A visual examination of the CSB/thermal shield assembly disclosed the thermal shield support system to be severely damaged. A number of thermal shield support pins were fractured and/or missing and damage to the CSB was visible. An evaluation of the thermal shield support system concluded that refurbishment was impractical. Therefore, a decision was made to remove the thermal shield. Analyses performed to evaluate operation without a thermal shield for its remaining design life indicated that replacement of the thermal shield was not necessary.

A structural evaluation of the repaired CSB and the reactor internals without the thermal shield was performed. The component stresses under normal, upset and faulted conditions were evaluated and found to be within the limits of Section III, Subsection NG 1972, Draft Edition of the ASME Nuclear Components Code. A reanalysis of the revised reactor internals was performed and is discussed in UFSAR Section 4.2.2.2.

The reactor internals are divided into four major parts consisting of the CSB, the lower core support structure and core shroud, the upper guide structure and CEA shrouds, and the incore instrumentation guide tubes. The flow skirt, although functioning as an integral part of the coolant flow path, is separate from the internals and is affixed to the bottom head of the reactor vessel. These components are described in UFSAR Sections 4.2.2.2.2 through 4.2.2.2.7.

The major support member of the reactor internals is the core support structure. The core support structure consists of the CSB and the lower support structure. The material used for the assembly is Type 304 stainless steel.

The effect of irradiation on the properties of the materials is considered in the design of the reactor internal structures.

UFSAR Table 4.1-1, Reactor Internals Stress Analyses Methods Summary identifies the reactor internal component, load condition, analysis technique and computer codes used in the stress analysis of the reactor internals.

The details of the dynamic analyses are described in UFSAR Section 3.9.1.

The review requirements associated with Note 1 of Matrix 2, Section 2.1 of NRC Review Standard (RS)-001 relates to NRC Information Notice (IN) 2002-26 and the failure of the steam dryers and other plant components at Quad Cities Units 1 and 2 during operation under EPU conditions. IN 2002-26 is BWR specific and therefore not applicable to St. Lucie Unit 1.

IN 95-016 is also BWR specific and therefore not applicable to St. Lucie Unit 1.

As stated in UFSAR Section 3.9.1.3, design analyses were performed on the reactor internals for normal operating conditions to demonstrate that the mechanical design bases defined in UFSAR Section 4.2 were satisfied. These design calculations included appropriate vibration analyses of the component assemblies.

UFSAR Section 3.9.4.1.3 describes the dynamic analysis performed to determine the structural response of the reactor vessel internals to the transient LOCA loadings.

In addition to the licensing basis described in the UFSAR, the RPV internals and core supports were evaluated for St. Lucie Unit 1 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 RPV 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 rod drive mechanisms. The reactor internals functional description is provided below. The reactor internals are designed to withstand forces due to normal, upset, emergency, and faulted conditions.

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 reactor vessel internals (RVI) addressed in this section comprise both core support and internal structures. Core support structures, which provide direct support/restraint of the reactor core, include the lower support structure (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 RVI 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 RVI 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 with a heavy ring flange at the top end and an internal ring flange at the lower end. The CSB is supported from a ledge on the reactor vessel. The CSB, in turn, supports the LSS upon which the fuel assemblies rest. The upper section of the barrel contains two outlet nozzles contoured to minimize coolant bypass leakage.

Since the weight of the CSB is supported at its upper end, it is postulated that coolant flow could induce vibrations in the structure. Therefore, 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 reactor 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 core support plate (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 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 comprises the LSS. 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 Assembly

The UGS assembly consists of the support plate assembly, CEA shrouds, and fuel assembly alignment plate. 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 CEAs from the effect 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 plate welded to a grid array of beams and a cylinder, which encloses and is welded to the ends of the beams. The CEA shrouds extend from the fuel assembly alignment plate to above the UGS support plate. The fuel assembly alignment plate is designed to align the upper ends of the fuel assemblies and to support and align the lower ends of the CEA shrouds. The fuel assembly alignment plate 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 fuel alignment plate (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 is composed of two welded assemblies, stacked one on top of the other and held together with tie rods. Each welded assembly consists of vertical panels, vertical ribs and horizontal plates. 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.

Incore Instrumentation Support System

The incore instrumentation system begins outside of the reactor vessel, penetrates the vessel boundary 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 provides a guide for each instrument and protects them from turbulent cross flow. The guide path consists of a conduit above the incore instrument support plate and incore thimbles which extend into the center of selected fuel assemblies. The conduit and incore thimbles are attached to and supported by the instrument plate assembly. The instrumentation plate assembly fits within the confines of the reactor vessel head and is supported on four of the extension shaft guide assemblies (ESGAs), which extend upward from the CEA shroud assemblies and are attached to the UGS support plate. The ESGAs extend through clearance holes in the instrumentation plate. Above the instrument plate, the conduits bend and are gathered to form instrument stalks which extend into the reactor vessel head instrumentation nozzles. The instrumentation plate assembly is raised and lowered during refueling to insert or withdraw all instruments and their thimbles simultaneously.

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 RCS 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 RVI components.

There are no assumptions made in these evaluations/analyses.

FPL has performed evaluations/analyses to assess the effect of operating at 3020 Mwt EPU on the RPV internals system of St. Lucie Unit 1. The analyses and evaluations 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 is consistent with the functional requirements of the components and to ensure 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 of St. Lucie Unit 1.

The results of the gamma heating rate calculation were incorporated into the thermal analysis of the RVI components, as well as the structural analysis of the RVI 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 the May 1972 draft of Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG. 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 1-9-2 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, or normal operating loadings plus design basis earthquake forces, deflections will be limited so that the CEAs can insert and adequate core cooling is maintained.

Under normal operating loadings plus design basis earthquake plus pipe rupture loadings resulting from a break of the largest line connected to the reactor coolant system piping, deflections will be limited so that the core will be held in place, adequate core cooling is maintained, and all CEA’s can be inserted. Those deflections which would influence CEA movement will be limited to less than 80% of the deflections required to prevent CEA insertion.

Under normal operating loadings plus design basis earthquake forces plus the maximum pipe rupture loadings resulting from the full spectrum of pipe breaks, deflections will be limited so that the core will be held in place and adequate core cooling is maintained. Although CEA insertion is not required for the largest reactor coolant system pipe break, calculations show that the CEAs can be inserted except for a few CEAs located near the vessel outlet nozzle which is feeding the postulated break.

CSB repair plug – flange deflection measurement tool readings must be greater than or equal to the minimum required values. Satisfying this criterion demonstrates that the plugs have sufficient preload to perform their intended function over the operating life of St. Lucie Unit 1.

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 RVI 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 plus upset, emergency and faulted conditions. The normal plus upset condition includes mechanical, hydraulic, thermal, and operating basis earthquake (OBE) loads. The emergency condition is the same as the normal plus upset condition, except that SSE loads are used instead of OBE loads. The faulted condition is the same as the emergency condition, except that LOCA loads are included as well. The stress limits for the emergency condition are midway between the stress limits for the normal plus upset conditions and the faulted condition. However, because the LOCA loads are so much higher than the normal operating and seismic loads, satisfying the stress limits for the faulted condition demonstrates that the stress limits for the emergency condition will be satisfied as well.

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. 1. 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.

In addition to the evaluations described above, the reactor internals components were evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are described and documented in NUREG-1779, Safety Evaluation Report (SER) Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, September 2003.

<u>Thermal-Hydraulic System Evaluations</u>

The design hydraulic loads were assessed for EPU conditions. The result of the assessment showed that EPU conditions increase the hydraulic loads by 2.4% for the thimble support plate (TSP), and 3.4% for all other components subjected to core exit temperatures. This increase was incorporated into the stress analyses and evaluations of the RVI 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 RVI. Fatigue curves in this edition of the Code were limited to 106 cycles. The calculation of high-cycle (> 106 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.

<u>Design Transients</u>

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 of RVI for the EPU.

<u>Mechanical System Evaluations</u>

LOCA Loads

The blowdown loads on the RVI that were calculated for the Asymmetric Loads program bound the loads for the EPU conditions. These are the loads that were previously analyzed for St. Lucie Unit 1. 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. Therefore, the seismic loads on reactor internals components are not affected by the EPU.

<u>Evaluation of Reactor Internal and Core Support Structure Components</u>

In addition to supporting the core, a secondary function of the RVI 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, providing adequate cooling capability. Some of the parameters influencing the mechanical design of the RVI assembly and evaluated here 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 analyses and evaluations were performed on the reactor internal components for the EPU conditions. The most critical components that were analyzed/evaluated are:

- Core support barrel

- Core support plate
- Lower support structure beams and columns
- Core shroud
- Upper guide structure
- Fuel alignment plate
- Control element assembly shrouds
- Instrument tube supports
- Reactor vessel level monitoring system support tube
- Thimble support plate

The results of these analyses/evaluations 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 EPU.

Core Support Barrel Repair Plug Assessment

Minimum plug-flange deflection requirements for measurements taken at the end of St. Lucie Unit 1 Cycles 5 and 6 was updated for EPU conditions, including revised hydraulic loads, fluence, and irradiation-induced relaxation input. The methodology of the existing analysis was then followed for EPU conditions. These requirements are then compared to actual deflection measurements.

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 RVI stress evaluation are presented in LR Table 2.2.3-1. Stress intensities in the RVI components 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 RVI components. The deflection of the extension shaft guide assemblies (ESGAs) attached to the UGS have 84% 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.

Actual CSB repair plug-flange deflection measurements exceed the minimum required values in all cases for EPU conditions. The plug-flange evaluation addressed the time-limiting aging analysis performed for license extension and demonstrates that the analysis is acceptable for 60-year operation.

LR Table 2.2.3-1 indicates that the core shroud primary plus secondary stress intensity exceeded the 3Sm limit imposed by the ASME Code. Acceptability of the core shroud was shown by applying the simplified elastic-plastic analysis identified by ASME Code Paragraph NG-3228.3. 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 3Sm. This is met for the core shroud.

NG-3228.3(b) requires that the value of Sa used for entering the design fatigue curve be multiplied by the Ke 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 3Sm.

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 its current licensing basis with respect to 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 RVI Components

Table 2.2.3-1 (Continued)
Stress Evaluation Results for RVI Components

Table 2.2.3-1 (Continued)
Stress Evaluation Results for RVI Components

Table 2.2.3-1 (Continued)
Stress Evaluation Results for RVI Components

2.2.4 Safety-Related Valves and Pumps

2.2.4.1 Regulatory Evaluation

The Florida Power & Light (FPL) review of St. Lucie Unit 1 included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the 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 extended power uprate (EPU) on the required functional performance of the valves and pumps. The review also covered any impacts that the EPU may have on the licensee's motor-operated valve (MOV) programs related to NRC Generic Letters (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:

- 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;
- 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for Safety-Related Valves and Pumps 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. 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 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 of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection systems that transfer between normal and emergency power sources, and the operation of the associated cooling water system.

The ECCS (safety injection system (SIS)) is provided with testing facilities to demonstrate system component operability. Testing can be conducted during normal plant operation with the test facilities arranged not to interfere with the performance of the systems or with the initiation of control circuits.

- 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 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. For the purpose of periodically testing the retentive capability of the filter systems, test panels are placed in the filter housings in locations which allow the panels to be subjected to the same air flow as the filters. These will be periodically removed and tested.

- 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 (LOCAs), 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 are demonstrated in this way. Pumps and heat exchangers are operated as dictated by plant operational modes and tested on a schedule 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 6.2.4.2.

Valves isolating penetrations serving engineered safety features systems will not automatically close with a containment isolation signal, 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 Table 6.2-16 for additional isolation valve information.

To ensure continued integrity of the containment isolation system, periodic closure and leakage tests shall be performed as stated in UFSAR Section 6.2.4.4, TS 3/4.6.1, and TS 3/4.6.3.

As addressed in UFSAR Section 3.9.2.11 a pump and valve IST Program for St. Lucie Unit 1 began its fourth ten year IST interval on February 11, 2009. This program will be conducted in accordance with the requirements of the 2001 Edition through 2003 Addenda of the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code). The IST Program ensures that safety-related pumps and valves will be in a state of operational readiness throughout plant life.

Technical Specification (TS) 6.8.4.i, Inservice Testing Program, addresses the test frequency requirements to be included in the IST Program.

Mechanical components in fluid systems whose operability is required to perform a safety function are considered active components. The operability of these components must be assured under the loading conditions they will be subjected to during a postulated accident including the design basis earthquake. Pumps and valves are the only active components relevant to St. Lucie Unit 1. 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,
- Maintain the safe shutdown condition, and/or
- 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 3.9.2.4, the requirements of GL 89-10 have been completed for the applicable valves, which are listed in UFSAR Table 3.9-6.

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 1 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 15, 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 St. Lucie Unit 1 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 St. Lucie Unit 1 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 was addressed in the system-specific sections of this licensing report.

2.2.4.2 Technical Evaluation

2.2.4.2.1 Introduction

<u>Inservice Testing Program</u>

As described in the plant administrative procedure, Inservice 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
- Maintaining the safe shutdown condition, and/or
- To mitigate the consequences of an accident

As stated in UFSAR Section 7.4, St. Lucie Unit 1 was designed and licensed to operate with the Hot Standby condition defined as the “safe shutdown” 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, Inservice Testing of Pumps and Valves,
- St. Lucie Plant Safety Analysis Report,
- St. Lucie Unit 1 Technical Specifications, and
- NUREG-1482, Rev. 1, Guidelines for Inservice 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 1 is based on the rules set forth in the 2003 Edition of ASME B&PV 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. NUREG 1482, Rev. 1 and GL 89-04, Guidance on Developing Acceptable Inservice Testing Programs, have 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 Nuclear Power Plants; and Mandatory Appendix II, Check Valve Condition Monitoring Program, with the limitations imposed by 10 CFR 50.22a(b)(3)(iv)(A), (B) and (D). Where these requirements are determined impractical, specific relief requests have been written.

As discussed in the IST Program, the following categories of valves are subject to inservice testing:

- 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 for which are self-actuating in response to some system characteristic, such as pressure (relief valves) or flow direction (check valves).
- Category D: Valves for which are actuated by an energy source capable of only one operation, such as rupture disks or explosive-actuated valves.
- N/A: Valves for which have been included into the IST Program as the result of either a regulatory or utility commitment.

Plant administrative procedure, ASME Code Testing of Pumps and Valves, provides 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 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 Setpoint Variation as a Result of Thermal Effects, addresses the effects of the thermal environmental conditions on main steam safety valve (MSSV) 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 offsite 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 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).
- 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 is 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.

As a result, FPL has received concurrence from the NRC that the requirements and conditions associated with the GL 89-10 MOV Program and associated attributes have been satisfied.

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 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 a 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:

- Valve maximum stroke times,
- Valve performance,
- Accident condition flow rates for check valves,
- Relief/safety valve set pressures,
- Containment isolation valve leakage rate testing,
- Pump performance,
- Generic Letter 89-10,
- Generic Letter 96-05,
- Generic Letter 95-07,
- AOV Program,
- Lessons learned,
- Impact of emergency diesel generator (EDG) frequency tolerance on MOV stroke times and IST Program test acceptance criteria, and
- 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 unrelated to EPU parameters, Topics 12 and 13 address 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 (± 1%) and a steady-state voltage of 4160 ± 210V (± 5%).

Since the description and results of the analyses and evaluations are interrelated, these elements of the technical evaluation are addressed in Section 2.2.4.2.4, 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 and UFSAR Table 6.2-16, the main steam line isolation valves (MSIVs) have a maximum closed stroke time of 6.0 seconds. This maximum closure time remains unchanged for the EPU.
- Per UFSAR Table 6.2-16, the motor-operated main feedwater (MFW) pump discharge isolation valves have a maximum closed stroke time of 60 seconds to terminate feedwater flow. This maximum closure time remains unchanged for the EPU.
- Per UFSAR Table 6.2-16, the hydraulically operated main feedwater isolation valves (MFIVs) have a maximum closed stroke time of 20 seconds. This maximum closure time remains unchanged for the EPU.
- Per TS 3/4.7.7, on receipt of a containment isolation signal, the control room ventilation system automatically isolates the control room within 35 seconds. The following system isolation valves have a maximum closure time of 35 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.
- 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 6.2-16 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.
- Per UFSAR Section 6.3.3.1, the motor-operated injection valves in the high pressure safety injection system have an opening time of not greater than 10 seconds; the motor-operated injection valves in the low pressure safety injection system have an opening time of not greater than 15 seconds. These maximum opening times remain 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,
  - High pressure safety injection system, 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 injection lines from RCS pressures will be at the new T_{cold} conditions, 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.

The evaluation shall include an analysis to determine the actuator inlet and outlet piping resistance along the normal discharge path and the rupture disc path. 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). The minimum required accident condition flow rates for the low pressure SIS are not affected by the EPU. Therefore the EPU does not affect the current stroke time performance of IST Program valves in this system.

For the high pressure SIS, although there is no change in the high pressure safety injection pump head performance (refer to Topic 6 below), the minimum required accident condition flow rates increase at EPU conditions (refer to LR Section 2.8.5.6.3. As addressed under Topic 7 below, for the GL 89-10 MOVs in NSSS scope systems, the MOVs will not be exposed to temperature, pressure, or flow conditions outside their original design specifications or the MOVs are sufficiently isolated from RCS conditions to preclude any necessity for consideration of any additional MOV Program evaluations. 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 the high pressure SIS.

The safety injection tank (SIT) recirculation control valves are safety-related air-operated valves in the high pressure SIS. The normal operating function of these valves is to relieve RCS check valve backleakage into the safety injection header. Although normally closed, these valves receive a SIAS to close. As addressed under Topic 10.b below, the maximum differential pressure used in the valve/actuator capability analysis for these valves remains bounding for EPU. Therefore, the EPU does not affect the current stroke time performance of these valves.

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, evaluation shows that each MSSV is capable of passing the required steam flow rate at 100 percent of the EPU rated thermal power.

As addressed in LR Section 2.5.5.1, evaluations show that the atmospheric dump valves (ADVs) are capable of performing their intended design functions at EPU conditions without modification. Based on the following considerations, the stroke time performance of these valves is not affected by the EPU: (1) the required thrust calculations for these valves use an upstream pressure of 1025 psig, which corresponds with the highest nominal setpoint of the MSSVs; as addressed in Topic 4 below, the highest nominal setpoint of the MSSVs (1040 psia) is not affected by the EPU, (2) as addressed in LR Section 2.5.5.1, the highest normal operating pressure of the main steam system, 885 psig, which occurs at no load conditions, is not affected by the EPU, and (3) the ADV capacities remain unchanged at EPU conditions.

As addressed in LR Section 2.5.5.1, the impact of higher main steam flow rates through the MSIVs at EPU conditions was evaluated. The evaluation confirmed satisfactory performance at EPU conditions, including the ability to meet the safety-related isolation function to prevent uncontrolled blowdown of both steam generators (SGs) in the event of a steam line rupture accident.

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 MSIVs are designed to use flow to assist in closure and, therefore the increased steam flow under EPU conditions will enhance the closing of the valve, thus ensuring that the TS requirements for closing time (6 seconds) are met.

As discussed in LR Section 2.5.5.1, modification of the MSIVs is required to improve the structural integrity and fatigue life of the valves in the event of a spurious closure at EPU conditions. This modification does not affect the safety-related function of the valves to close under accident conditions.

As addressed under Topic 7 below, for main steam system MOVs in the IST Program, the EPU does not affect the maximum differential pressures 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 valve, and overall gear ratios of the actuators) are not affected by the EPU; therefore, the uprate does not affect the stroke time performance of MOVs in the main steam system.

Main Feedwater System

As addressed in LR Section 2.5.5.4, the hydraulically operated MFIVs have been evaluated for the increased flow rates, differential pressures, and temperatures at EPU conditions. The valve vendor confirmed that the increased flow rates and corresponding velocities will not adversely affect the functional performance of the MFIVs, including the valve closure time.

As addressed under Topic 7 below, for the motor-operated MFW pump discharge valves, 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 capability of these valves to close within the maximum closure time of 60 seconds.

As addressed in LR Section 2.5.5.4, containment isolation is accomplished by the provision of MFIVs and the check valves on the feedwater headers outside containment. These 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 pressures and temperatures of the AFW suction and discharge piping segments remain bounding under EPU conditions, and therefore the existing design parameters of the AFW system components (e.g., valves) are adequate for EPU operation.

As addressed in LR Section 2.5.4.5, the check valves that function as containment isolation valves for the AFW system are capable of supporting the containment isolation function after EPU implementation.

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.

Component Cooling Water 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 SDCS 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 EPU does not affect the CCW system flow rates; there is no change in the CCW pump head performance, and therefore there is no change in 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 RCP cooling water supply and return valves is addressed under Containment Isolation Valves Communicating with the Containment Atmosphere below.

Intake Cooling Water 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 maximum operating temperature setpoints for the CCW and ICW systems remain unchanged at EPU conditions. 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 Sections 2.5.4.2 and 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 this system.

Containment Spray System

The containment spray system maximum operating temperature is based on the sump 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 maximum containment pressure at the Recirculation Actuation Signal (RAS) is bounded by the maximum containment pressure at RAS at current plant conditions (refer to LR Table 2.2.4-1). Therefore, EPU system operating pressures are bounded by current system operating pressures. 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 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 temperature in the secondary side of the SGs is slightly reduced (0.4°F) for EPU operation; the EPU does not impact current SGBS flow requirements. The EPU either does not impact current system operating pressures, or the operating pressure at current conditions bounds the operating pressure at EPU conditions.

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 controls resulting from the EPU. Therefore, the EPU does not affect the capability of the following system isolation valves to close within the TS 3/4.7.7 required closure time of 35 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.

Shield Building Ventilation System

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 motor-operated valves in these lines. There is no significant change in the differential pressure across the motor-operated valve in the filter subsystem cross-connect line at EPU conditions, and therefore the EPU does not affect the stroke time performance of the motor-operated valve in this line.

Instrument Air System

As addressed under Topic 7 below, the EPU does not affect the maximum differential pressure used for determining the MOV stem thrust and actuator torque values at current conditions for the GL 89-10 MOV in the instrument air system. There are no new or additional instrument air system demands for EPU. The flow rate, pressure, and temperature of the compressed air passing through the instrument air system containment isolation valve are expected to remain within the original design parameters. Therefore, the EPU does not affect the current stroke time performance of the containment isolation valve in the instrument air system.

Primary Makeup Water 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 GL 89-10 MOV in the primary makeup water system. The primary makeup water system is not affected by the EPU. Therefore, the EPU does not affect the current stroke time performance of the containment isolation valve in the primary makeup water system.

c. Containment Isolation Valves Communicating with the Containment Atmosphere

Table 6.2-16 of the UFSAR identifies lines which are open directly to containment atmosphere and connected to non-seismic Class 1 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 LOCA, P_a, increases from 39.6 psig at current conditions to 42.8 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 air supply and exhaust valves (containment purge system)

  Currently, during operational Modes 1 through 4, the 48-inch containment purge valves have their power removed; plant management approval is required to perform a containment purge during these modes. As addressed in LR Section 2.7.7, a modification to the containment hydrogen purge system will be implemented for EPU to provide a suitable means for limiting the initial containment pressure during operation at power, similar to St. Lucie Unit 2. The containment isolation valves in the modified hydrogen purge system will be required to close against the maximum differential pressure in the event of a LOCA. Required changes to the St. Lucie Unit 1 IST Program associated with this modification will be performed as part of the plant change/modification process. Impact of this modification on the AOV Program is addressed under Topic 10.

- Nitrogen supply valve to containment (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.

- Reactor coolant pump cooling water supply and return valves (component cooling water 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 maximum expected differential pressure (MEDP) for this scenario, 44 psi, is based on the containment design pressure, 44 psig. However, the MEDP used in the actuator capability calculation, 136.6 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 since 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 uses the containment design pressure, 44 psig, for both the upstream and downstream pressures. The actuator capability analysis for these valves states that the worst case differential pressure for these valves to close 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 and sample return 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 psig and a differential pressure of 44 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 the 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.

3. Accident Condition Flow Rates For Check Valves

As indicated in LR Section 2.2.4.2.1, full stroke exercising of check valves to the open position is verified by passing 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/portions of systems:

- Chemical and volume control system,
- Low pressure safety injection system,
- Containment spray system,
- Auxiliary feedwater system,
- Component cooling water system,
- Intake cooling water system, and
- Steam supply to the steam-driven AFW pump.

With the exception of the high pressure SIS, the EPU does not affect the current minimum required accident condition flow rates, or the current minimum required accident condition flow rates remain bounding, for check valves in the above-listed systems/portions of systems.

For the high pressure SIS, although there is no change in the high pressure safety injection pump head performance, the minimum required accident condition flow rates increase at EPU conditions (refer to LR Section 2.8.5.6.3). Update of the IST Program to document the revised flow rates for check valves in this system will be performed as required during the EPU Implementation Phase.

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,
- Low pressure safety injection system, and
- Shutdown cooling system.

The setpoint of the SIT relief valves will be increased from 250 psig to 280 psig for the EPU (refer to LR Section 2.8.5.6.3). Required changes to the IST Program/AOV Program to implement this modification will be performed as part of the plant change/modification process.

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 "±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, 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 39.6 psig. As addressed in LR Section 2.6.1, the value of P_a at EPU conditions is 42.8 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 will be revised to incorporate the value of P_a at EPU conditions.

6. Pump Head Performance

There is no change in pump head performance for the following pumps at EPU conditions, and therefore, the reference flow rates used for testing these IST Program pumps are not affected by the EPU.

- Boric acid makeup pumps,
- Charging pumps,
- High pressure injection pumps,
- Low pressure 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 reference 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, and
- Diesel soak back lube oil DC pumps.

The impact of EDG frequency tolerance on IST Program pump test acceptance criteria is addressed under Topic 12.

7. NRC 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.

- Main Feedwater System

  LR Table 2.2.4-1 summarizes the existing MEDP data for the MFW system valves potentially affected by the EPU. MFW system parameters used for evaluating operator capability are not affected by EPU. As discussed in the table, the current MEDP for the MFW system MOVs is 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 spray system valves potentially affected by the EPU. As discussed in the table, the current MEDP for the containment spray system MOVs remains bounding at EPU conditions.

- Intake Cooling Water System

  ICW system parameters used for evaluating operator capability are not affected by the EPU.

- Instrument Air System

  Instrument air system parameters used for evaluating operator capability are not affected by the EPU.

- Primary Makeup Water System

  Primary makeup water system parameters used for evaluating operator capability are not affected by the EPU.

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 motor operated valves in these systems were affected:

- Reactor coolant system,
- Chemical and volume control system, and
- Emergency Core Cooling System - 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 limits used for the existing GL 89-10 MOV electrical and mechanical calculations to establish operator requirements. As indicated in LR Section 2.3.3, changes to available voltage values at the 480V motor control center (MCC) buses under the worst case accident scenario at EPU conditions are acceptable. 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 the current 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 there is no significant impact to MOV performance.

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 in 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 2.13.1, the PRA model has been evaluated for the EPU 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. NRC Generic Letter 95-07

FPL has performed modifications on SDCS gate valves to address concerns expressed in GL 95-07. Bypass lines have been installed around the RCS side of the valve seats to eliminate the potential for pressure locking. This modification was reviewed by the NRC and found 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.

- Containment Purge System

  As addressed under Topic 2 above, during Operational Modes 1 through 4, the 48-inch containment purge valves currently have their power removed. A modification to the containment hydrogen purge system will be implemented for EPU to provide a suitable means for limiting the initial containment pressure during operation at power. Required changes to the AOV Program associated with this modification will be performed as part of the plant change/modification process.

- 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. Containment spray system parameters used for evaluating operator capability are not affected by the EPU. As discussed in the table, the current MEDP for the containment spray system AOVs is not exceeded by EPU.

- 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.

The system level design basis review calculations for AOVs in the following BOP systems were also reviewed.

- Component Cooling Water System

  CCW system parameters used for evaluating operator capability of CCW system AOVs are not affected by the EPU.

- Intake Cooling Water System

  ICW 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 waste management 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 air operated valves 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.

As addressed in LR Section 2.8.5.6.3, the maximum operating pressure of the SITs will be increased from 250 psig to 280 psig for the EPU. It has been determined that this change does not affect the valve/actuator capability analysis for the Category 1 SIT recirculation control valves in the high pressure SIS; the maximum upstream line pressure used in the calculation of maximum differential pressure for these valves is based on the maximum RCS normal operating pressure, which is not affected by the EPU. Therefore, the maximum differential pressure used in the valve/actuator capability analysis for these valves remains bounding for EPU.

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 2.13.1, 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 Test Acceptance Criteria

Although unrelated to EPU parameters, 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 (± 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 ± 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 reference 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 unrelated to EPU parameters, a TS change has been submitted with this license amendment request to require that the EDGs operate at a steady-state voltage of 4160 ± 210V (± 5%).

    For MOVs with AC motors powered by the EDGs, the voltage tolerance of ± 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 ± 5% will not adversely 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 its 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 NRC GL 89-10 Program
Impact to Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Current Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Impact
Main Steam	MV-08-1A/1B	MSIV Equalizer	985 psid (O) 1015 psid (C)	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.	None
			Note: Bounding upstream pressure (O) is based on lowest main steam safety valve (MSSV) nominal setpoint (985 psig). Bounding upstream pressure (C) is based on lowest MSSV nominal setpoint plus MSSV accumulation.	Notes: 1. EPU does not affect lowest MSSV nominal setpoint, MSSV accumulation, or maximum MSSV backpressure. 2. Maximum SG pressure in the current analysis of loss of load to one SG bounds the maximum SG pressure in the EPU analysis of this event.	
	MV-08-3	AFW Pump Turbine Steam Throttle/Trip	1048 psid (O) 1048 psid (C)		
			Note: Bounding upstream pressure (O/C) is based on maximum steam generator (SG) pressure determined in the analysis of loss of load to one SG.		
	MV-08-13/14	AFW Pump Turbine Steam Supply	1010 psid (O) 1010 psid (C)		
			Note: Bounding upstream pressure (O/C) is based on lowest MSSV nominal setpoint (985 psig) plus maximum MSSV backpressure.		

Table 2.2.4-1 (Continued)
BOP MOV NRC GL 89-10 Program
Impact to Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Current Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Impact
Main Feedwater (MFW)	MV-09-01/02	MFW Pump Discharge Isolation	858.3 psid (O) 1178 psid (C)	Current MEDPs for MFW System MOVs not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded.	None
			Note: Bounding upstream pressure (O/C) is based on MFW pump head at minimum recirculation flow and condensate pump head at same flow. Bounding downstream pressure (O) is based on SG zero load pressure. Bounding downstream pressure (C) is based on trip setpoint of the main steam isolation signal (MSIS)	Notes: 1. As addressed in LR Section 2.5.5.4, replacement MFW pumps will be installed for EPU. Existing MFW pump head at minimum recirculation flow bounds the replacement pump head at minimum recirculation flow. Condensate pump head used in the current analysis remains bounding. 2. EPU does not affect SG zero load pressure. 3. EPU does not affect MSIS trip setpoint.	

Table 2.2.4-1 (Continued)
BOP MOV NRC GL 89-10 Program
Impact to Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Current Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Impact
Auxiliary FeedWater (AFW)	MV-09-9/10	AFW Pump Discharge Isolation Valves to Steam Generators 1A/1B	1462 psid (O) 1462 psid (C)	Current MEDPs 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.	None
			Note: Bounding upstream pressure (O/C) is based on motor-driven AFW pump maximum discharge pressure.		
	MV-09-11/12		1344 psid (O) 1344 psid (C)	Notes: 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.	
			Note: Bounding upstream pressure (O/C) is based on steam-driven AFW pump maximum discharge pressure.		
Containment Spray	MV-07-2A/2B	Containment Sump Outlet Isolation	26.6 psid (O), 26.6 psid (C)	Current MEDP for Containment Spray System MOVs remains bounding at EPU conditions.	None
			Note: 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.	Note: The EPU maximum containment pressure at RAS for all LOCA line break cases is bounded by the current containment pressure at RAS for the LOCA DEDLS break case.	

Table 2.2.4-2
BOP AOV Program
Impact to Actuators at EPU Conditions

System	AOV Program Valves (Cat. 1)	Description	Current Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Conditions: Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	EPU Impact
Main Steam	HCV-08-1A/1B	Main Steam Isolation	0 psid (O) 995.3 psid (C) Note: Bounding upstream pressure for the safety-related close stroke is based on lowest main steam safety valve nominal setpoint plus 1% tolerance.	For safety-related close stroke, current MEDP is exceeded by EPU MEDP. Note: Bounding upstream pressure for the safety-related close stroke is based on lowest main steam safety valve 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.
Steam Generator Blowdown	FCV-23-3/5	Containment Isolation	1061.5 psid (O) (C) Note: Bounding upstream pressure for the safety-related close stroke is based on highest main steam safety valve nominal setpoint plus 1% tolerance.	For safety-related close stroke, current MEDP is exceeded by EPU MEDP. Note: Bounding upstream pressure for the safety-related close stroke is based on highest main steam safety valve 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	Current Conditions	EPU Conditions	EPU Impact
			Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)	**Maximum Expected Differential Pressure (MEDP) Opening (O) – Closing (C)**	
Containment Spray	LCV-07-11A/B	Reactor Cavity Sump Pump Discharge	1 psid (O) 41 psid (C)	Current MEDP not exceeded by EPU.	None
			Note: Bounding upstream pressure for the safety-related close stroke is based on containment design pressure.	Note: EPU does not affect containment design pressure.	
	FCV-07-1A/1B	Containment Spray Flow Control	243.7 psid (O) 15 psid (C)	Current MEDP not exceeded by EPU.	None
			Note: Bounding upstream pressure for the safety-related open stroke is based on Unit 2 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 the Unit 2 containment spray actuation signal (CSAS) setpoint.	Note: EPU does not affect St. Lucie Unit 2 containment spray pump shutoff head, St. Lucie Units 1/2 RWT high level alarm setpoint, or Unit 2 CSAS setpoint.	

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. FPL's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to the design basis earthquake (DBE) are not affected by an EPU. Note that DBE is a term used during original plant licensing. Current seismic analyses use the term safe shutdown earthquake (SSE) to denote the same event. Thus, both DBE and SSE may be found in the plant documentation.

Acceptance criteria are based on:

- 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 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;
- 10 CFR 50, Appendix B, which sets quality assurance requirements for safety-related equipment.

Specific review criteria are contained in SRP Section 3.10.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of FPL are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the FPL design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for seismic and dynamic qualification of mechanical and electrical equipment 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.

All 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 1. 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, 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 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 DBE. 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 DBE. 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 DBE.

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.

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, 3.7.5 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.

Reactor coolant system (RCS) components are designed in accordance with the ASME Code Section III, and ANSI B 31.7. Quality control, inspection, and testing as required by this standard and the allowable reactor pressure-temperature operations ensure the integrity of the RCS.

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

- 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 the codes and standards specified in Criterion 14.

The seismic qualification provisions generally meet the requirements of IEEE-344-1971, *IEEE Guide for Seismic Qualification of Class 1E Electric Equipment for Nuclear Power Generating Stations,* although the guide was not in existence at the time of issuance of the FPL construction permit.

10 CFR 100 Appendix A sets forth the principal seismic and geologic considerations which guide the NRC in its evaluation of the suitability of proposed sites for nuclear power plants and the suitability of the plant design bases established in consideration of the seismic and geologic characteristics of the proposed sites. UFSAR Section 2.1 describes the site location and geographic features. The effects of site-related parameters on the seismic response spectra are discussed fully in UFSAR Section 2.5.2.

NRC Generic Letter 87-02 requested that licensees review the seismic qualifications of mechanical and electrical equipment to resolve Unresolved Safety Issue A-46. By letter dated February 9, 1995, the NRC notified FPL that the response to the generic letter was acceptable, but that several additional items would require further evaluation. These additional items were evaluated and closed out by the following safety evaluation report:

- Supplemental Safety Evaluation by the Office of Nuclear Reactor Regulation—Evaluation of the Florida Power & Light Company's Response to Generic Letter 87-02—St. Lucie Unit 1 and Turkey Point Units 3 and 4 (Issued by letter dated October 22, 1996)

UFSAR Section 3.6 describes the design criteria and bases for protecting essential equipment from the effects of piping failures inside and outside of containment. Leak-before-break criteria has been adopted to provide an alternative means to treat RCS hot leg and cold leg loop piping whip criteria per NUREG-1061. Generic Letter 87-11 was adopted as an alternative means to provide pipe break protection for Class 2, Class 3, and Non ASME Class systems to minimize the addition of or facilitate the removal of excess arbitrary intermediate pipe whip restraints.

In addition to the licensing basis described in the UFSAR, the seismic and dynamic qualification of mechanical and electrical equipment was evaluated for St. Lucie Unit 1 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 FPL 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 of the EPU on FPL seismic design, seismic inputs, and seismic loads was evaluated in order to determine the impact of the EPU on the seismic qualification of essential FPL equipment and supports.

The impact of the EPU on high energy/moderate energy line break locations, and on the protection features currently in place for protection of essential FPL 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 FPL 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 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.

2.2.5.2.4 Results

Seismic design is not impacted by the FPL 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 FPL 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 FPL essential equipment from the dynamic effects of pipe whip and jet impingement (e.g. jet impingement shields). Therefore, the qualification of FPL 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 FPL 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 3.9-3A and 3.9-3B.

Evaluations related to seismic and dynamic effects of the FPL EPU are addressed in the following LR Sections:

- LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects
- LR Section 2.3.1, Environmental Qualification of Electrical Equipment

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 100, Appendix A; and 10 CFR 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. FPL's 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;
- 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 reactor coolant pressure boundary 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 RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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.

All 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, 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 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 design basis earthquake (DBE). 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 DBE. 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 DBE.

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, and ANSI B 31.7. 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.

Design pressures, temperatures and transients are listed in UFSAR Chapter 5 and details of the transient analysis are provided in UFSAR Chapter 15.

Means are provided to detect significant leakage from the RCPB with monitoring readouts and alarms in the control room as discussed in UFSAR Chapters 5 and 12.

The RCPB has provisions for in-service inspection as described in UFSAR Section 5.2.5, to ensure the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with ASTM-E-185 is provided as discussed in UFSAR Chapter 5.

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

The operating conditions established for the normal steady-state and transient operation and anticipated operational occurrences are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin in maintained between the plant operating conditions and the design limits.

The reactor protective system (RPS) (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain anticipated operational occurrences; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the reactor coolant pressure boundary are not exceeded in the event of any AOO.

Design parameters for both normal and transient conditions are derived from the performance objectives of the system and its components. UFSAR Section 5.2.1.2 presents cyclic transients, which include conservative estimates of the operational requirements for the components used in the fatigue analyses required by the applicable codes listed in UFSAR Table 5.2-1.

Pressure and temperature fluctuations resulting from the transients identified in UFSAR Section 5.2.1.2 are computed by means of computer simulations of the reactor coolant system. Computer output entailing time dependent physical parameters throughout the RCS are detailed in the component specifications. The component vendor then uses the specification transient curves as the basis for fatigue design.

Fatigue analysis for each component of the reactor coolant system is performed in accordance with the applicable ASME codes. As appropriate, the combined effects of the load and thermal transients specified for each condition of cyclic operation are evaluated as a function of time. The evaluations are performed in a manner to yield the maximum range in stress intensity during the particular cyclic condition under consideration. In those cases where conservative results are produced, peak stresses due to pressure may be combined with those due to thermal transients by direct superposition. In addition, the results of analysis obtained for the most severe transient condition in a group may be applied in evaluating the cumulative effects of the entire group.

Pressure and thermal stress variations associated with the design transients are included in the engineering design of each of the RCS components, piping, and supports. In addition, the loads and moments resulting from the design transients are included in the design of equipment support foundations and interfacing support structures for the equipment.

The codes adhered to and component classifications are listed in UFSAR Table 5.2-1 and conform to 10 CFR 50.55.

Cyclic loading outside the NSSS scope of design is addressed in UFSAR Section 3.9.2.2.

The RPS is designed to assure adequate protection of the fuel, fuel cladding and RCPB during AOOs. Those NSSS conditions which require protective system action are discussed in detail in UFSAR Chapter 15.

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 St. Lucie Unit 1 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 to 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 Table 2.2.6-1, NSSS Design Transients – Reactor Vessel[a], Reactor Coolant Pumps, and Pressurizer, Table 2.2.6-2, NSSS Design Transients – RCS Piping, and Table 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 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 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 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 1 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[(a)], Reactor Coolant Pumps, and Pressurizer

Transient Description	Number of Occurrences[(b)]	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[(d)]
Step Load Increase of 10% of Full Power per Minute	2000	No
Step Load Decrease of 10% of Full Power per Minute	2000	No
Normal Plant Variation	10^6	No
Pump Starting and Stopping (RCPs only)	4000	No
Reactor Trip, Loss of Load	400	No
Loss of Primary System Flow	40	No
Abnormal Loss of Load	40	No
Design Loadings plus Design Earthquake	200	No
Operational Basis Earthquake (Pressurizer only)	200	No
Safe Shutdown Earthquake (SSE) plus Normal Operation at Full Power (Pressurizer only)	1	No
SSE plus Normal Operation at Full Power plus Pipe Rupture (Pressurizer only)	1	No
Normal Operating Loadings plus Maximum Earthquake	1	No
Normal Operating Loadings plus Pipe Rupture plus Maximum Earthquake	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[(c)]	No

a. Includes the reactor vessel head.
b. The number of occurrences and type of transients are the same as the existing design basis, unless otherwise noted.
c. The replacement reactor vessel head and the replacement control element drive mechanisms are designed to 320 cycles for this transient.
d. 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[a]	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[b]
Step Load Increase of 10% of Full Power per Minute	2000	No
Step Load Decrease of 10% of Full Power per Minute	2000	No
Normal Plant Variation	10^6	No
Reactor Trip	400	No
Loss of Primary System Flow	40	No
Loss of Load	40	No
Design Loadings plus Design Earthquake	200	No
Loss of Secondary Pressure	5	No
Normal Operating Loadings plus Maximum Earthquake	1	No
Normal Operating Loadings plus Pipe Rupture plus Maximum Earthquake	1	No
Hydrostatic Test, 125 psia, 160°F-400°F	10	No
Leak Test, 2250 psia, 160°F-400°F	200	No

a. The number of occurrences and type of transients are from the same as the existing design basis, unless otherwise noted.
b. 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[a]	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[b]
Plant Unloading at 5% of Full Power per Minute	15,000	Yes[c]
Step Load Increase of 10% of Full Power per Minute	2000	Yes[c]
Step Load Decrease of 10% of Full Power per Minute	2000	Yes[c]
Cold Feedwater following Hot Standby	15,000	No
Normal Plant Variation	10^6	No
Pump Starting and Stopping	4000	No
Reactor Trip	400	Yes[c]
Loss of Reactor Coolant Flow	40	Yes[c]
Loss of Load	40	No
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	N/A
SSE plus Normal Operation plus FWLB Pipe Rupture	1	N/A
Hydrostatic Test, 3125 psia, 100°F-400°F	10	No
Secondary Side Hydrostatic Test, 1250 psia	10	No

Table 2.2.6-3 (Continued)
NSSS Design Transients – Steam Generators

Transient Description	Number of Occurrences[(a)]	Transient Parameters Required Revision due to the EPU
Leak Test, 2250 psia, 100°F-400°F	200	No
Secondary Side Leak Test, 1000 psia	200	No

a. The number of occurrences and type of transients are from the same as the existing design basis, unless otherwise noted.
b. Revision to NSSS parameter T_{cold} change from 550°F to 551°F
c. At the time the replacement steam generators (SGs) were installed, the NSSS steam generator 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 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 SRP Section 3.11.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

UFSAR Section 3.11 describes the St. Lucie Unit 1 historical licensing basis for environmental qualification of equipment and the EQ program. UFSAR Section 18.2.6 describes the EQ program with respect to license renewal.

St. Lucie Unit 1 was originally required to meet IEEE 323-1971 for the EQ of equipment. In January 1980 the NRC issued IE Bulletin 79-01B to which St. Lucie Unit 1 responded. In February 1983. The requirements for the EQ of electrical equipment were codified in Title 10, Part 50, Section 49 of the Code of Federal Regulations (10 CFR 50.49). This section required all holders of an operating license issued prior to February 22, 1983, to develop and complete a program for the qualification of equipment subject to 10 CFR 50.49 by the end of the second refueling outage after March 31, 1982, or by March 31, 1985, whichever came first.

Pursuant to the requirements of 10 CFR 50.49, FPL has established a program for qualifying the electrical equipment defined in paragraph (b) of 50.49. The list of equipment subject to these requirements is provided in drawing 8770-A-450, "Environmental Qualification (EQ) List for 10 CFR 50.49". EQ Documentation Packages (Doc Pacs, drawing series 8770-A-451) provide the qualification documentation for this equipment. Doc Pac 1000 (drawing 8770-A-451-1000) provides the "design basis" for the program.

Pursuant to the requirements of IE Bulletin 79-01B, FPL reevaluated the EQ of equipment used for accident mitigation or post-accident monitoring irrespective of whether it is categorized as Class 1E or not. This equipment was evaluated against the Enclosure 4 Guidelines of the Bulletin as discussed in FPL's phase II report responding to the Bulletin. The evaluation included a detailed review of the DBA service conditions during which accident mitigating and post-accident monitoring equipment is required to function and the qualification test reports to ensure the equipment was tested within those service conditions.

The service conditions considered were:

- Inside containment for a loss-of-coolant accident (LOCA)
- Inside containment for main steam line break (MSLB)
- Outside containment for high energy line break (HELB)

On November 26, 2008, via Amendment No. 206 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.

In addition to the licensing bases described in the UFSAR, the EQ of electrical equipment was evaluated for St. Lucie Unit 1 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 each of the following areas:

- Reactor containment building
- Post-accident operability time (PAOT)
- Reactor auxiliary building
- 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 Doc Pac number.

A comparison of current temperature and pressure conditions with EPU LOCA and 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 that 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 areas, 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 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 a change in the normal operating pressure range as a result of a Technical Specifications (TS) change being implemented for EPU. The resultant pressure range is bounded by the current conditions and therefore has no affect on the environmental qualification of the equipment. Refer to LR Section 2.7.7.

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 for current conditions are based on design considerations and source terms corresponding to a core power level of 2700 MWt, 1% fuel defects, and a traditional 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 33 years, and operation at the EPU power level for the remaining 27 years. A 10% margin is included to address possible uncertainty in survey measurements. Refer to subsection 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 temperature is bounded by the current peak EQ temperature profile as shown on Figure 2.3.1-1 and remains below the EQ envelope during the PAOT period. 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 affect on the qualification of the equipment as the peak tested conditions still envelope current EQ LOCA and MSLB accident pressure profile and, thereby, the peak EPU pressure profile.

Accident Conditions – Humidity:

The current accident humidity is 100%. The relative humidity level remains unchanged from the current accident humidity due to EPU.

Accident condition – pH:

The pH range of 7.0 to 10.84 has changed for EPU from the 8.5 to 11.0 range for pre-EPU value. However, there is no impact to the EQ equipment inside containment as a result of this change in pH range from EPU.

Accident condition – Submergence:

Following EPU, the submergence elevation showed an increase (less than an inch of water) to the maximum flood level due to temperature difference. Based on a review of equipment inside containment, there is no impact.

Accident Conditions – Radiation:

The accident radiation doses used for radiological EQ for current conditions are based on the TID-14844 nuclide release assumptions; i.e., following a LOCA, 100% of the core noble gases, 50% of the core halogen, and 1% of the core remainder are instantaneously released from the fuel into the containment.

St. Lucie Unit 1 is approved for the use of AST as outlined in 10 CFR 50.67 and RG 1.183 for post-accident dose assessments associated with the offsite and onsite 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 RG 1.183 which indicates that though EQ analyses impacted by plant modifications should be updated to address the impact of the modification, and 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 EQ 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 RG 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 2.0E+08 rads, and on the detailed calculations documented in Appendix D of NUREG-0588, i.e., a beta dose of 1.4E+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 (AST). A limited sub-set of the core inventory of dose-significant nuclides developed using ORIGEN 2.1 is presented in 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% 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.

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 is developed based on source term guidance provided in NUREG-0737 (i.e., instantaneous homogeneous mix of 100% of the core noble gases, and 50% 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, temperature, and pressure during 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 in Figure 2.3.1-1 demonstrates that the peak accident temperature for the EPU operation is bounded by the current EQ profile for equipment qualification. Therefore, the equipment is qualified for the EPU accident transient conditions.

LR Figure 2.3.1-1 that 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 that the accident pressure curves are bounded by the current EQ 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 2.25E+7 rads gamma plus 1.25E+08 rads beta for a total integrated dose of 1.48E+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 dose plus the total integrated gamma dose was assessed for potential beta dose reduction. 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 normal bulk average temperature does not change); 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.

2.3.1.2.2.2 Post-Accident Operability Time

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 envelope 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 maximum normal design 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; therefore, the pressure is not affected and the RAB pressure is not impacted by EPU.

Normal Conditions – Humidity:

The 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:

The pH under normal pre-EPU conditions 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.

Accident Conditions – Pressure:

The pressure in the RAB has not changed as a result of EPU operation.

Accident Conditions – Radiation:

As previously discussed, the impact of the EPU on the accident environmental gamma dose estimates is developed using scaling techniques that reflects 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 analysis of record.

The results of a comparison of 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 5.25E+7 rads against the qualification values determined that the EQ of equipment currently in the EQ Program is not impacted due to EPU.

However, as a result of EPU, localized areas, previously mild areas, on the 43-foot elevation of the RAB in the vicinity of the shield building ventilation system HEPA and charcoal filters could receive a total integrated dose greater than 1E+05 rads.

Walkdowns were conducted to identify equipment in these localized areas that are credited for post-accident mitigation. Component-specific total integrated doses were conservatively determined based on dose versus distance calculations. Field measurements of source to component distances were conservatively based on the closest filter edge. Based on the measured distances, the dose calculation conservatively assumed the component was located along the centerline of the filter largest face. This results in the following components in the RAB HVAC area receiving total integrated doses greater than the harsh radiological environment threshold of 1E+5 rads. FPL will install equipment shielding (in the form of steel plating), as needed to reduce the component-specific total integrated doses to less than 1.0E+5 rads for the following components:

- RAB main supply fan (HVS-4A),
- Shield building exhaust fan (HVE-6A),
- Motor for damper D-23, and
- Motor for damper D-24.

A bounding dose of 3.94E+05 rads is conservatively calculated for damper motor D-24, which is a fail-open fan discharge damper motor for the "B" train shield building ventilation system. The bounding dose for the corresponding "A" train damper motor D-23 is 2.34E+5 rads, and the dose for the larger fan motors, HVS-4A and HVE-6A, are 1.25E+5 rads and 1.04E+05 rads, respectively.

A shielding calculation was performed to estimate the required shield thicknesses. Using data from Table 5.4, Shield Thickness Versus Gamma Dose Transmission, from "A Handbook of Shielding Data," ANS/SD-76/14, July 1976, the iron shielding thicknesses were determined modeling the iron data for a mono-energetic source (Co-60 with a ~1 MeV γ), where the transmission factor versus shield thickness is a straight line on semi-log paper.

From these data, an equation was developed to calculate required shield thicknesses to reduce the total integrated doses to a target dose, that is, to achieve a dose reduction factor (DRF) equal to the ratio of the total integrated dose to the target dose. The equation is as follows:

$$10^{x/3.2} = \text{DRF}$$

Solving for x by taking the log of both sides of the equation:

$$x = 3.2 \log \text{DRF}$$

Where:

x = required shield thickness,

3.2 = thickness, in inches, needed to achieve a DRF of 10,

DRF = ratio of the total integrated dose to the target dose.

The thicknesses of steel shielding that would reduce the exposure levels from the calculated total integrated doses (EPU levels) to a target dose of 9.5E+04 rads are given in LR Table 2.3.1-1. The resultant shielding thicknesses are conservative, since the assumed γ source energy of 1 MeV is generally greater than the maximum γ decay energy of the iodine isotopes assumed to be have been collected in the shield building ventilation system charcoal adsorbers, and further, the selected target dose is below the threshold EQ value of 1.0 E+5 rads.

Plant structural design was reviewed to determine the feasibility of installing the required shielding. It was concluded that shielding can be installed to protect the impacted equipment without affecting structural integrity, equipment operation and maintenance.

Accident Conditions – Humidity:

The humidity in the RAB has 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.

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 0 psig; there is no change in pressure as a result of EPU.

Normal Conditions – Humidity:

There is no change in the humidity (100%) as a result of EPU.

Normal Conditions – Radiation:

The radiation dose for normal operation is 1.50E+02 rads and has not changed by EPU.

Normal Conditions – pH:

The pH under normal pre-EPU conditions is not applicable in the trestle area and is unaffected by EPU.

Accident Conditions – Temperature:

The pre-EPU accident temperature in the trestle area of 320°F (the trestle area is open to the atmosphere and the temperature effects, the 320°F, is the localized temperature effects of a HELB and does not affect the entire area) is not changed by EPU operation.

The localized MSLB accident temperature of 320°F is exceeded by a few degrees for a matter of seconds while steam is flowing; however, this has been evaluated for qualified equipment in the trestle area and found not to have an impact.

Accident Conditions – Pressure:

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% in the trestle area is not changed by EPU operation.

Accident Conditions – Flooding:

Submergence (flooding) is not applicable for the trestle area and is not affected by EPU.

Accident Conditions – pH:

The pH is not applicable in the trestle area and is not affected by EPU. There is no impact to EQ in the trestle area due to EPU.

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. 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

LR Table 2.3.1-2 summarizes the results of EPU impact on environmental qualification of electrical equipment.

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 results in the components in the RAB HVAC area listed in LR Section 2.3.1.2.2.3 requiring shielding to resolve the EQ issue. Shielding for these four components will be installed prior to operation at EPU conditions.

The containment accident temperature and pressure profiles are bounded by the existing EQ 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 EQ 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 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 St. Lucie Unit 1 current licensing basis requirements with respect to the requirements of 10 CFR 50.49 following implementation of the proposed EPU. With regards to the components listed in LR Table 2.3.1-1, FPL commits to installing shielding to maintain radiological exposures below the threshold EQ value of 1.0E+5 rads. FPL finds the proposed EPU acceptable with respect to the EQ of the electrical equipment.

Table 2.3.1-1
Dose and Shielding Information for Impacted Electrical Equipment

Component Tag No.	Component Description	Total Integrated Dose (Rad)	Target Dose (Rad)	Approximate Required Shielding (Inches of steel)
HVS-4A - MTR	RAB main supply fan (HVS-4A)	1.25E+05	9.5E+04	0.4
HVE-6A - MTR	Shield building exhaust fan (HVE-6A)	1.04E+05	9.5E+04	0.1
D-23 MTR OPER	Motor operator for damper D-23	2.34E+05	9.5E+04	1.3
D-24 MTR OPER	Motor operator for damper D-24	3.94E+05	9.5E+04	2.0

Table 2.3.1-2
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	• Upper end of normal operating range decreased by EPU • 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	No change	No change
Pressure	Bounded by current pressure profile	No change	No change
Humidity	Current relative humidity is 100%; unchanged by EPU	No change	Current relative humidity is 100%; unchanged by EPU

Table 2.3.1-2 (Continued)
Summary of Results of EPU Impact on Environmental Qualification of Electrical Equipment

Parameter	Reactor Containment Building	Reactor Auxiliary Building	Steam Trestle
pH	• pH range is increased • No EQ impact from change	N/A	N/A
Submergence/ Flooding	• Submergence level increased • No impact to equipment due to equipment elevations	No change	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	• Calculated using bounding scaling factors • Total integrated dose is increased for EPU • Equipment currently in EQ program is not impacted • Localized area of the 43' elevation in the vicinity of the shield building ventilation system HEPA and charcoal filters have become a harsh environment • Motors affected: - HVS-4A - HVE-6A - HVE-6B - D-23 - D-24 • Will be resolved by shielding prior to EPU implementation	No change to normal total integrated dose

Figure 2.3.1-1
Unit 1 Containment LOCA and MSLB Accident Temperature Profiles vs. Plant EQ Profile

(Solid Thin Lines = LOCA Cases 1 through 9, Broken Lines = MSLB Case 6, Solid Thick Lines = EQ Analysis of Record)

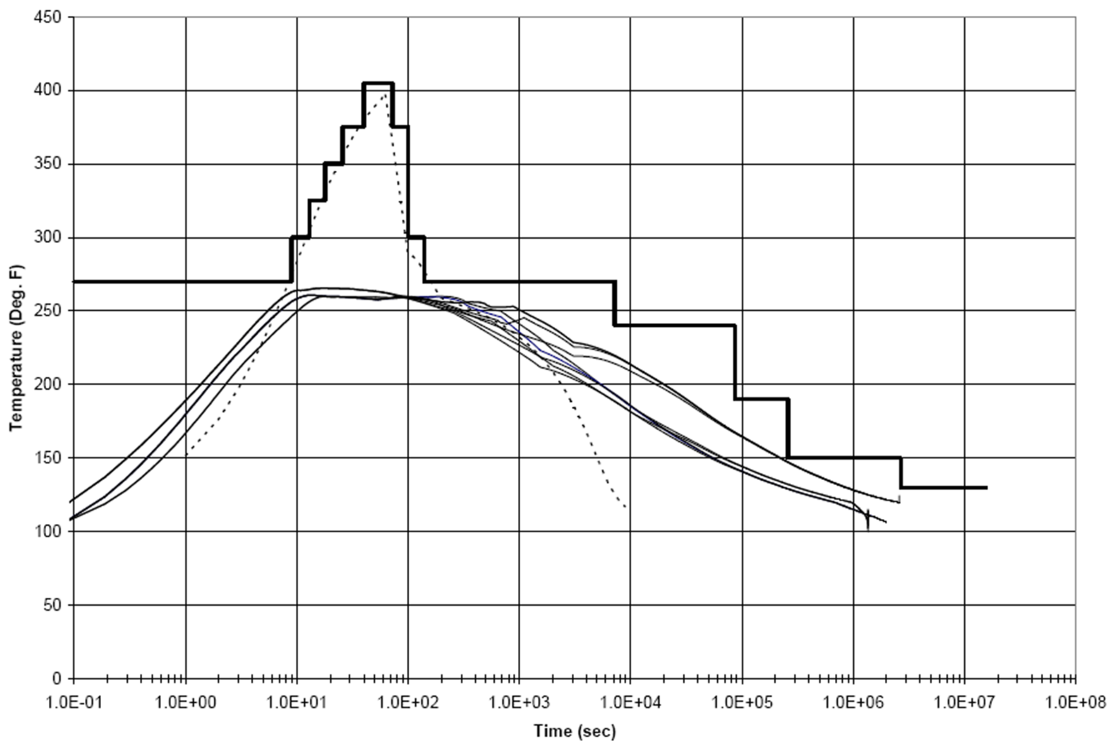
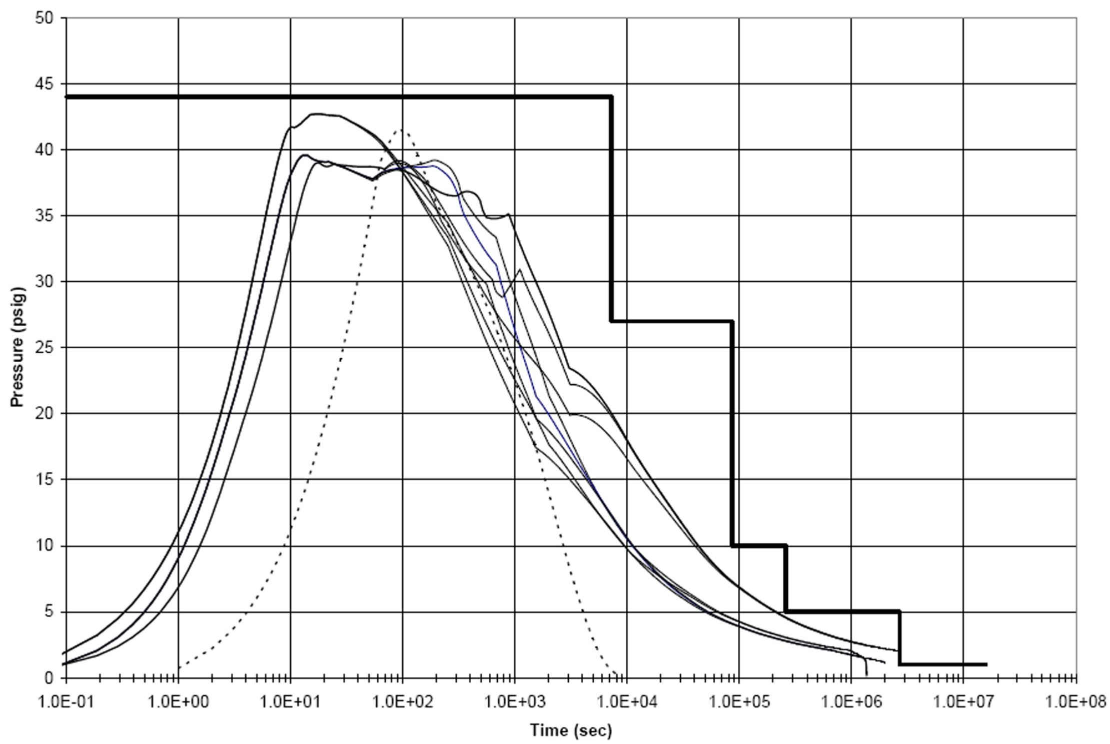


Figure 2.3.1-2
Unit 1 Containment LOCA and MSLB Accident Pressure Profiles vs. Plant EQ Profile

(Solid Thin Lines = LOCA Cases 1 through 9, Broken Lines = MSLB Case 6, Solid Thick Lines = EQ Analysis of Record)



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 included the descriptive information, analyses, and referenced documents for the offsite power system and the stability studies for the electrical transmission grid. FPL's review focused on whether the trip of either 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 extended power uprate (EPU).

The NRC's acceptance criteria for offsite power systems are based on GDC-17

Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions PSB-1 and ICSB-11.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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 to assure that core coolant, containment integrity, and other vital safety functions are maintained.
>
> Provisions shall be included to minimize the probability of losing electrical 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, there will be 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.

Section 8.2.2.2 of the UFSAR identifies reliability considerations that satisfy the requirements of AEC GDC-17 and Safety Guide 32 for offsite power systems and minimize the probability of power failure due to faults in the network interconnections and associated switching. Of note is the result of the system stability analysis, which demonstrates that the loss of St. Lucie Unit 1 or the largest generating unit on the system other than St. Lucie Unit 1 does not negate the ability to provide offsite power to St. Lucie Unit 1 engineered safety features loads.

A turbine trip initiates a generator lockout to prevent generator damage. A turbine trip with the failure of one or both of the generator breakers to open does not affect safe shutdown of the reactor or prevent mitigating the consequences of a LOCA. If the generator breaker fails to open (breaker located in the switchyard), the generator circuit could still be cleared by the remaining switchyard and/or remote line terminal breakers. Thus, two sources of offsite power will still be immediately available.

Refer to UFSAR Section 8.2.2.3 relative to the transient stability study performed for St. Lucie Unit 1, 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.

Additional details associated with the offsite power systems can be found in UFSAR Sections 8.1.2.1 and 8.2.

In addition to the licensing basis described in the UFSAR, the offsite power system 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 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 8.1 and 8.2.

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 circuit is carried on a separate transmission tower, with circuits 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 lightning protection equipment. One of the three 230 kV transmission lines can supply all of the plant auxiliary power.

The five bay 230 kV (nominal) switchyard which is arranged in a breaker-and-a-half configuration, provides switching capability for two main generator outputs, four startup transformers (SUTs), three outgoing transmission lines, and the Hutchinson Island distribution substation.

The main generator is directly connected through a 22 kV, isolated phase bus to the main transformers (MTs) 1A and 1B, where it is stepped up to 230 kV nominal and enters the 230 kV switchyard through the overhead tie-lines.

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 a single overhead tie-line 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 the 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;
- 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 H to Attachment 5 of the EPU LAR.

2.3.2.2.4.2 Offsite Power System Components

Transmission Lines

Transmission lines are discussed in UFSAR Sections 8.2.1.1 and 8.2.2.2. 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 the spacers between the existing bundled phase conductors, fiber optic overhead ground wire on all three lines, and replacement of associated disconnected switches. 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 have 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 230 kV switchyard and the main transformers 1A and 1B high voltage side have been evaluated for EPU conditions. The evaluation determined that the tie-lines are acceptable for use under EPU conditions. The tie-lines are protected by a differential protection scheme with inputs from current transformers located at the main transformers high side and at the associated switchyard breakers. The evaluation also confirmed that existing tie-lines differential protection schemes are adequate for upgraded tie-lines in consideration of EPU loads.

Startup Transformers Tie-Lines

The existing tie-lines between the 230 kV 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 on 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 & 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 SRP Sections 8.1 and 8.3.1 and guidance is provided in Matrix 3 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

Specifically, the adequacy of the ac onsite power system design relative to:

- GDC-17 which 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 to assure that core coolant, 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 the main generator via the auxiliary transformers, there will be 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 8.2.1 and 8.3.2 for further discussion of offsite power sources and onsite power sources, respectively.

The normal source of auxiliary ac power for plant startup or shutdown is from the incoming offsite transmission lines through the plant switchyard and startup transformers.

Each of the unit auxiliary and 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 basis described in the UFSAR, the ac onsite power system was evaluated for St. Lucie Unit 1 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 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 the 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 (IPB) ducts, 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 1A and 1B and UATs 1A and 1B through IPB ducts.

The function of the IPB ducts is to conduct electrical power from the main generator to the MTs 1A and 1B and UATs 1A and 1B.

The function of the two three-phase, two winding MTs 1A and 1B 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 1A and 1B 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 1A and 1B 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 when the UATs 1A and 1B 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 1A1 and 1B1 is from 4.16 kV buses 1A2 and 1B2, 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 1A2 and 1B2 respectively with a swing load group AB served by 480 volt bus 1AB. Power is transmitted from the 4.16 kV emergency buses through the station service transformer to 480 volt buses 1A2 and 1B2. The swing bus 1AB is normally tied to either one of the redundant emergency 480 volt buses but never both at the same time.

The function of the two EDGs, 1A and 1B, 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 requiring an unregulated power. Some of the 120/208 volt panels feed safety-related loads such as engineering 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 MCC and 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, the MT cooling package electrical loading increases and an increase in size of the IPB duct cooling fan motors. The modifications are briefly described below:

- Replace the existing current limiting reactors (CLRs) in 480V LCs 1A2/1B2 with new CLRs having lower impedances,
- Trip the non-safety bus sections from 480V MCCs 1A5/1B5, and 1A6/1B6 on a safety injection actuation signal (SIAS),
- Change the electrical feeds for the heating and ventilation system fans 1-HVS-4A/4B from 480V MCCs to 480V LCs,
- Trip 4.16 kV motors for the heater drain (HD) and condensate pumps on a SIAS. The main feedwater (FW) pumps will also be tripped by existing circuitry. Because the new MT cooler package loading is increasing significantly, these loads will also be tripped. Similarly, the new

IPB duct cooling fan motors are increasing from 25 hp to 100 hp and will have their electrical feeds moved from an MCC to the same LCs that feed the transformer cooling package. These loads may also be tripped on a SIAS.

- Repowering 480V MCCs 1A4 and 1B4 from a non-power block source through a transfer switch that would also allow these MCCs to be fed from their existing power block sources during refueling outages or from an independent source during power operations.

Main Generator

The main generator is discussed in UFSAR Section 8.2.1.4. 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 1052.1 MW @ 0.89 power factor lagging. The generator capability curves show that the modified main generator will be capable of continuous operation at this level and adequate to support unit operation at EPU conditions, including machine leading and lagging reactive power requirements, 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 (CT) (35,000:5 rating) require replacement with new CTs (40,000:5 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 8.2.1.4. 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 MT tap bus will be upgraded to 33.2 kA and 16.6 kA (by upgrading 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 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. The over duty condition on IPB tap buses will be further analyzed and corrective action, as appropriate, completed 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 isolated phase bus duct main and tap bus continuous and short circuit ratings are adequate to support unit operation at EPU conditions.

Main Transformers 1A and 1B

The generator step up MTs 1A and 1B are discussed in UFSAR Section 8.2.1.4. 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 from 475 MVA to 635 MVA at 65°C, with additional coolers to support generator output at EPU conditions. The existing MT 1A will have its cooling unit upgraded. The existing MT 1B is to be swapped with existing spare transformer. The existing spare transformer is to be relocated as new MT 1B and have its associated coolers upgraded. The evaluation confirms that the modified MT ratings are adequate to support output of the main generator, and envelop the anticipated worst-case loading at EPU conditions.

The existing MT protection requires revised relay setpoints to support operation at EPU conditions.

Unit Auxiliary Transformers 1A and 1B

The existing three-winding UATs 1A and 1B are discussed in UFSAR Section 8.3.1.1.1. Each transformer FOA design rating at 65°C is 39.2 MVA @ 22 kV high voltage winding, 23.6 MVA @ 6.9 kV low voltage winding, and 15.7 MVA @ 4.16 kV low voltage winding. The EPU evaluation determined that the existing UAT 65°C design ratings for the high voltage and both low voltage windings envelope the anticipated worst-case loading on the UATs at EPU conditions, therefore 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 1A and 1B

The existing three-winding SUTs 1A and 1B are discussed in UFSAR Section 8.2.1.3.

Each SUT, 1A and 1B, is rated 21/28/35/39.2 MVA: SUT 1A - oil air/forced air/forced oil and air at 55°C rise/forced oil and air at 65°C rise (OA/FA/FOA at 55°C/FOA at 65°C); SUT 1B - oil air/forced oil air (one cooling bank)/forced oil air at 55°C rise (both cooling banks)/forced oil air at 65°C rise (both cooling banks) (OA/FOA/FOA at 55°C/FOA at 65°C), double secondary winding, 230-6.9-4.16 KV. The SUT 1A 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 rise/FOA at 65°C rise. The SUT 1B 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 at 55°C rise (both cooling banks)/FOA at 65°C (both cooling banks).

The EPU evaluation determined that the existing SUT 65°C design ratings for the high voltage and both low voltage windings envelope the anticipated worst-case loading on the SUTs at EPU conditions, therefore, are adequate to support unit operation at EPU conditions.

The existing SUT 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 8.3.1.1.2. 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 6.9 kV 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 steady-state motor terminal voltages are above the allowable minimum design values at existing and EPU conditions. The evaluation indicates that the maximum steady-state motor terminal voltages exceed the allowable maximum motor design voltage at existing and EPU conditions. This is a current plant design issue. A slight overvoltage condition (by less than or equal to 0.5%) is identified for the FW pump motors during Mode 1 plant operation with the main generator operating at maximum voltage of 22.5 kV. Such mild overvoltage conditions are not a concern based on actual plant experience. Taking into consideration that the 6.9 kV bus motor overvoltage condition has been reduced at EPU conditions to less than or equal to 0.5% of the 6600 V motor rating, the system 6.9 kV voltage levels are adequate to support operation at 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 is 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 condition.

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 8.3.1.1.3. 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 condensate 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 condensate 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 steady-state motor terminal voltages are above the allowable minimum design values. The table indicates that the maximum steady-state motor terminal voltages do not exceed the allowable maximum motor design voltage. Therefore, the motor terminal voltages are within the allowable voltage range at EPU conditions.

The evaluation demonstrates that there is 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 condensate 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 condensate 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 condensate 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 8.3.1.1.1.4. The 480 V system is comprised of seven 480 V load center buses 1A1, 1B1, 1A2, 1B2, 1A3, 1B3 and 1AB supplied from the 4.16 kV system through 4160 V/480 V station service transformers (SSTs) which are normally powered from the UATs or SUTs.

The 480 V system load changes under EPU conditions are as follows:

- The horsepower of the high pressure (HP) oil seal back-up pump motor on non-safety-related MCC 1A-1, powered from load center 1A1, will be increased from 20 hp to 40 hp.
- The 60 hp supply fan motors 4A and 4B will be removed from MCCs 1A5(SA), 1B5(SB), and repowered from 480 V load centers 1A2 & 1B2 which are safety related. However there is no load increase in load center bus load because associated MCCs are in the same load group.
- The 25 hp IPB duct cooler fan motors will be replaced by 100 hp fan motors and will be removed from MCCs 1A1 and 1B1 and re-powered from 480 V load centers buses 1A1 and 1B1.

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 and HP oil seal back-up 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.

480 V Motor Control Centers:

The impact of the EPU on the affected MCC steady-state continuous load currents is an increase in load on MCC buses 1A1 and 1B1, and a decrease in load on MCC buses 1A5(SA) and 1B5(SB). The load flow calculations determined that the load current requirements are enveloped by the MCC bus design ratings.

The 480 V MCC circuit breakers are rated 14 kA, 22 kA, 25 kA or 30 kA (symmetrical) interrupting ratings. The short circuit calculations determined that the fault duties on the circuit breakers rated 22 kA, 25 kA or 30 kA are enveloped by the equipment design ratings. However, the 14 kA rated circuit breakers on the buses 1A5, 1A6, 1B1, 1B5 and 1B6 are overduty and scheduled for replacement with a 25 kA rated circuit breakers prior to EPU.

Therefore, the evaluations determined that the 480 V load center and MCC buses and circuit breakers will be 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 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 1A1 and 1B1. The supply fan motors 4A and 4B will be powered from 480 V load centers 1A2 and 1B2. The HP AC seal oil backup pump motors rated 20 hp will be replaced by new 40 hp motors on MCC 1A1. 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.

Emergency Diesel Generators

The EDGs are discussed in UFSAR Section 8.3.1.1.7. The continuous rating of the EDGs is 3500 kW with additional short term ratings of 3730 kW (2000 hour) and 3960 kW (30 minutes). 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 120/208 V Power Systems

The 120 VAC instrument power system and 120 V/208 V power system are discussed in UFSAR Sections 8.3.1.1.5 and 8.3.1.1.6. 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 V/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 V/208 V 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

<table>
<tr><th rowspan="4">Unit Operation</th><th colspan="4" rowspan="3">Generator Output</th><th colspan="5">IPB Bus</th></tr>
<tr><th colspan="2">Main Bus</th><th colspan="3">Main Transformer Tap Bus</th></tr>
<tr><th>EPU Load</th><th>EPU Design Rating</th><th>Tap Bus 1A Load</th><th>Tap Bus 1B Load</th><th>EPU Design Rating</th></tr>
<tr><th>MW</th><th>MVAR</th><th>MVA</th><th>PF %</th><th colspan="5">kA</th></tr>
<tr><td>Lagging</td><td>1052.1</td><td>538.128</td><td>1181.73</td><td>89.0</td><td>30.63</td><td rowspan="2">33.2</td><td>15.33</td><td>15.30</td><td rowspan="2">16.60</td></tr>
<tr><td>Leading</td><td>1052.1</td><td>-300</td><td>1094.03</td><td>96.2</td><td>30.02</td><td>15.02</td><td>14.99</td></tr>
</table>

Table 2.3.3-2
6.9 kV Switchgear bus Steady-State Maximum Current

Bus	Rating (A)	Existing Load (A)	Maximum EPU Load (A)
1A1	2000	1198	1214
1B1	2000	1198	1214

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)
1A1-3	1200	Feedwater 1A	7000	530	482	498
1B1-3	1200	Feedwater 1B	7000	530	484	498

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)
1A1	76	58.8	58.8
1B1	76	58.8	58.9

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)
1A1	37,599	36,005	37,616	35,576
1B1	36,290	34,369	36,301	34,482

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)
1A2	1582	58	1598	58	3000	80
1A3 (SA)	398	49	394	49	1200	80
1B2	1591	58	1604	58	3000	80
1B3 (SB)	394	49	389	49	1200	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)
1A2	1200	HD pump 1A	1500	187	157	142
1B2	1200	HD pump 1B	1250	160	159	145
1A2	1200	TCW pump 1A	250	34	27	31
1B2	1200	TCW pump 1B	250	36	27	31
1A2	1200	Condensate pump 1A	4000	516	409	439
1B2	1200	Condensate pump 1B	4000	516	410	439

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)
1A2	44,171	33,801	44,127	33,855
1A3(SA)	44,171	30,280	42,210	30,313
1B2	44,171	33,963	44,095	34,018
1B3(SB)	44,171	30,157	44,184	30,188
1AB(SAB)	44,171	28,349	44,210	28,377

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 1A	250	4042	4129	3600	4424	4252	4400
TCW pump 1B	250	4030	4132	3600	4428	4240	4400
HD pump 1A	1500	4042	4129	3600	4424	4252	4400
HD pump 1B	1250	4030	4132	3600	4427	4240	4400
Condensate pump 1A	4000	4039	4126	3600	4422	4248	4400
Condensate pump 1B	4000	4028	4130	3600	4426	4238	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)
1A1(1)	1382	1464	2500	34,964	35,636	39,900
1A1(2)	1202	1162	1600	19,874	19,915	29,300
1A2(1) (SA)	1583	1553	2500	39,531	39,694	39,900
1A2(2) (SA)	667	587	1600	19,728	27,943	29,300
1A3	823	834	1000	17,981	17,968	22,000
1AB (SAB)	156	154	1600	31,278	31,375	39,900
1B1(1)	1527	1607	2500	34,265	34,938	39,900
1B1(2)	1527	1484	1600	19,979	20,029	29,300
1B2(1) (SB)	1549	1509	2500	39,152	39,257	39,900
1B2(2) (SB)	589	506	1600	19,303	27,508	29,300
1B3	822	832	1000	17,557	17,543	22,000

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)
1A1(1)	30	26	26
	65	26	26
1A1(2)	30	15	15
1A2(1) (SA)	30	29	29
	50	29	29
	65	29	29
1A2(2) (SA)	30	15	21
1A3	30	13	13
1AB (SAB)	30	23	24
	50	23	24
1B1(1)	30	25	26
	65	25	26
1B1(2)	30	15	15
1B2(1) (SB)	30	29	29
	50	29	29
	65	29	29
1B2(2) (SB)	30	14	20
1B3	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 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

Specifically, the adequacy of the dc onsite power system design relative to:

- GDC-17, Electrical Power Systems, is described in UFSAR Section 3.1.17 as follows:

  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 electrical 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.

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 St. Lucie Unit 1 UFSAR Section 8.3.2 for further discussion of the onsite dc power system.

In Generic Letter 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 1 met the reporting requirements of the generic letter.

With respect to electrical separation relative to the dc onsite power system, as stated in part in UFSAR Section 8.3.2.2.2, there are no direct connections between parts of the system which serve load group A and those parts which serve load group B. There are no automatic transfers of loads between load groups A and B. Buses serving load group AB can be manually connected with either of the buses serving load groups A or B. Ties from the AB buses to the A or B buses have a breaker at each end of the tie. Interlock is provided to prevent closing both ties at the same time. Administrative procedures call for tying the AB buses on all ac and dc voltage levels to the same load group (either A or B).

Physical separation as a protection against common failure of dc power to both redundant dc load groups has been achieved by spatial separation and/or erection of physical barriers between redundant portions of the dc system.

In addition to the licensing basis described in the UFSAR, the dc onsite power system was evaluated for St. Lucie Unit 1 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 2.5.1.1.2 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 125 VDC buses (1A and 1B), one 125 VDC swing bus (1AB), and two 125 VDC non-safety buses (1C and 1D).

As described in UFSAR Section 8.3.2, the dc systems have the following key design attributes:

The Class 1E dc system for each unit is divided into redundant trains (A and B) that include one bus for each train (1A & 1B) and a common swing bus (1AB) between the two. 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 1AB swing bus is normally tied to the 1B bus. There are also non-Class 1E loads supplied (via isolation devices).

The Class 1E 1A and 1B batteries are 60 cells with capacity of 2400 amp-hours each at 300A 8-hour discharge rate. Each battery's capacity permits 4 hours of emergency operation without assistance from a battery charger. Each stationary battery supplies power for 125 VDC safety loads that include control power for Class 1E 4160V and 480 VAC switchgear and inverters for critical 60 cycle instrument power along with some non-Class 1E loads as previously noted.

The two batteries provide two separate sources of dc power for engineered safety features equipment; Train A equipment is supplied from battery 1A and Train B equipment is supplied from battery 1B.

There are two 100% capacity, continuously operating static battery chargers for each Class 1E 125 VDC bus; battery chargers 1A and 1AA for Train A and chargers 1B and 1BB for Train B. A fifth battery charger on the AB bus (1AB) provides backup for any of four operating battery chargers.

The non-Class 1E 125 VDC System for each unit consists of two batteries 1C and 1D, 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 125 VDC 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.

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 125 VDC Systems were evaluated to determine potential impacts due to EPU conditions.

There are two plant modifications that are planned to be implemented for Unit 1 that will affect the safety-related portions of the 125 VDC System:

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

The EPU load increases on the 1A and 1B 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 least amount of available margin) was the SBO coping case. For Battery 1A, the additional first minute loading associated with EPU (20.0A) represents a 8.0% load increase, with a pre-EPU margin of 44.1%. For Battery 1B, the additional first minute loading associated with EPU (20A) represents a 4.6% load increase, with a pre-EPU margin of 34.5%.

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

In addition, Station Blackout and 10 CFR 50, Appendix R program evaluations did not result in any 125 VDC System load changes, as discussed in LR Sections 2.3.5 and 2.5.1.4.

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 1 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 ac electric power to the essential and nonessential switchgear busses 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 busses fed by station batteries through inverters or the loss of power from “Alternate AC sources” (AACs). The Florida Power & Light (FPL) review focused on the impact of the proposed EPU on the plant’s ability to cope with and recover from the 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 RS-001, Review Standard for Extended Power Uprates.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report, for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971.

10 CFR 50.63 requires light-water-cooled nuclear power plants to be able to withstand and recover from the SBO event of a specified duration. The duration is based on the following factors:

- The redundancy of the onsite emergency ac power sources;
- The reliability of the onsite emergency ac power sources;
- The expected frequency of loss of offsite power; and
- The probable time needed to restore offsite power.

UFSAR Section 15.2.13 describes how the plant can successfully withstand and recover from the SBO event. The design basis SBO event is a four-hour event. The SBO analysis credits the availability of an emergency diesel generator (EDG) from St. Lucie Unit 2 as an AAC source. At one hour, operator action is credited for manual operation of the atmospheric dump valves (ADVs). Prior to one hour, the main steam safety valves cycle to control reactor coolant system (RCS) temperature and secondary pressure. In addition to the SBO event, a concurrent reactor coolant pump (RCP) seal leak of 25 gpm per pump (100 gpm total) was assumed, based on generic industry guidance. Total initial RCS leakage assumed in the current SBO analysis, including allowable RCS leakage per Technical Specifications (TS) is 120 gpm.

The SBO rule requires that the following issues be addressed: SBO duration, condensate inventory for decay heat removal, Class 1E battery capacity, compressed air, effects of loss of ventilation, containment isolation, reactor coolant inventory, procedures and training, quality assurance and TS, and the EDG reliability program. The NRC Safety Evaluation (Reference 1) and supplemental Safety Evaluation as documented in Reference 2 concluded in part that the St. Lucie Unit 1 method of coping with the SBO is acceptable.

UFSAR Section 15.2.13 addresses SBO relative to Section 2.3.6 of Reference 1 “Reactor Coolant Inventory”. Other requirements for the SBO rule are discussed in UFSAR Sections 8.3 and 9.4.

Analyses performed have shown that St. Lucie Unit 1 can successfully withstand the SBO event for at least four hours. Specifically:

- Adequate RCS inventory is maintained to ensure sufficient core cooling and to ensure that the core does not uncover;
- There is no fuel failure;
- RCS coolant pressure remains within limits, and;
- The resulting radiological dose rates are bounded by the LOOP event (UFSAR Section 15.2.9).

In addition to the licensing basis described in the UFSAR, the systems required to mitigate the 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 the SBO event are within the scope of license renewal. The programs used to manage the aging effects associated with the systems required to mitigate the 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

The SBO rule (10 CFR 50.63) requires that each light-water-cooled nuclear power plant be able to withstand and recover from the SBO event of a specified duration. The rule requires licensees to submit information as defined in Part 50.63 and to provide a plan and schedule for conformance to the SBO rule. The rule further requires that the baseline assumptions, analysis, and related information be available for NRC review.

The NRC prepared an SER for the license renewal of St. Lucie Units 1 and 2. The SER considered structures, systems, and components (SSC) and the NRC credited applicable SSCs to perform their intended functions to comply with the SBO rule and the criteria of the license renewal rule. The SER credits the use of a St. Lucie Unit 2 EDG as an AAC source.

The analysis performed in support of this EPU submittal and described herein demonstrates the ability to cope with the SBO event for four hours; the first hour with no ac power available followed by three hours powered by the AAC source. The one-hour dc coping is assumed to start at the actual time of the SBO. Attachment 8, 10 CFR 50.63 Station Blackout DC Coping, to this LAR provides an analysis of the station's ability to cope for up to one hour without alternate ac power available.

2.3.5.2.2 Acceptance Criteria

The NRC's acceptance criteria for the SBO Rule are based on 10 CFR 50.63. Specific review criteria are contained in NUREG-0800, SRP Section 8.1, Electric Power – Introduction, Appendix B to SRP Section 8.2, Guidelines for Review of Alternate AC Sources for SBO at Nuclear Power Plants and other guidance provided in Matrix 3 of RS-001.

2.3.5.2.3 Description of Analysis and Evaluation

A summary of the impacts of the EPU on the following SBO-related plant functions and programs is provided, since these are potentially affected by the EPU:

1. SBO Coping Duration,
2. Condensate Inventory for Decay Heat Removal and Plant Cooldown,
3. Class 1E Battery Capacity,
4. Compressed Air,
5. Effects of Loss of Ventilation,
6. Containment Isolation,
7. Reactor Coolant Inventory,
8. Auxiliary Feedwater (AFW) Flow,
9. Plant Procedures and Training,
10. Modifications Required to Cope with Station Blackout,
11. Quality Assurance,
12. Technical Specifications,
13. EDG Reliability Program, and
14. License Renewal.

1. SBO Coping Duration

The minimum acceptable SBO coping duration for St. Lucie Unit 1 utilizing the guidance of Regulatory Guide (RG) 1.155, Station Blackout, and the methodology of NUMARC 8700 Rev. 0, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors (Reference 3) has been determined to be four hours as stated in UFSAR Section 15.2.13. No ac power is assumed available for the first hour of the event; the alternate ac source is assumed to be available for the subsequent three hours of the event. The current SBO coping duration category is based on the following characteristics and criteria from NUMARC 8700.

- Allowed (minimum) EDG target reliability,
- Site susceptibility to grid-related LOOP events,
- Extremely severe weather group,
- Severe weather group,
- Offsite power system independence group, and
- Emergency ac power sources configuration.

LR Section 2.3.2 cites EPU grid stability studies and recommends modifications to maintain necessary stability. The recommended modifications will successfully maintain required grid stability and not increase the likelihood of the SBO event. The remaining five attributes listed above are independent of the EPU. Therefore, the EPU does not affect the current SBO coping duration.

2. Condensate Inventory for Decay Heat Removal and Plant Cooldown

At inception of the SBO event and after receiving a steam generator (SG) low-level signal, the turbine-driven auxiliary feedwater (TDAFW) pump delivers 600 gpm to two SGs to remove reactor decay heat, taking suction from the condensate storage tank (CST). The analysis assumes the unit to be at hot standby conditions during the one-hour dc coping period, followed by cooldown toward shutdown cooling conditions for the remaining three hours of the SBO event.

The condensate inventory required for decay heat removal for the four-hour SBO event duration at EPU conditions has been determined to be bounded by 130,500 gallons, the volume required for plant cooldown at a rate of 75°F/hr. The current TS Section 3.7.1.3 states that the CST shall be operable with a minimum usable volume of 116,000 gallons. A revision to TS 3.7.1.3 is proposed to increase the minimum total contained volume to 153,400 gallons to provide sufficient cooling water for the EPU operating conditions (See LR Section 2.5.4.5). Since the CST has sufficient capacity to provide this volume, the EPU will not impact the ability to cope with the SBO event.

3. Class 1E Battery Capacity

During the SBO event, all battery loads are electrical devices (such as breakers, relays, inverters, motor-operated valves, lube oil pumps). As stated in UFSAR Section 8.3.2, power is provided at 125V dc for plant control and instrumentation and for operation of dc motor-operated equipment such as valve operators and emergency lube oil pumps. The 125V dc system is arranged into two main redundant load groups, Train A and Train B, and a third service or swing load group, Train AB. Train A and Train B are each capable of supplying the minimum dc power requirements to safely shut down the plant.

Each of the two 125V dc lead-calcium type station safety batteries is rated at 2400 ampere/hr at an eight-hour discharge rate, which is sufficient for a four-hour emergency period without assistance from a battery charger.

An engineering evaluation of the 125V dc system concludes that EPU conditions do not increase loads on the station batteries during the SBO event, thus the ability of the dc system to perform its design function while maintaining adequate margin is maintained.

4. Compressed Air

The compressed air system is not required to achieve safe shutdown during the SBO event. However, as a matter of operator convenience, the station air compressors may be manually loaded onto AAC-powered Class 1E busses to meet air demands.

At the inception of the SBO event, manual and automatic operations (i.e., fail safe positions and air accumulators) overcome initial loss of compressed air until AAC is available. None of the essential control or monitoring instrumentation is pneumatic (UFSAR Section 7.4.2.4). Electrical instrumentation is powered from the associated 125V dc busses. As such, the following will not affect the operation of any safety-related component on the corresponding systems upon loss of compressed air:

- The main steam isolation valves (MSIVs) fail “as is” on loss of ac power, and are provided with air accumulators to enable their closure in accordance with the SBO emergency operating procedure.
- The EDGs are each provided with a seismic Class 1 air starting system independent from the station compressed air system as depicted in LR Section 2.5.7.1.
- The component cooling water (CCW) system non-essential (N) header isolation valves have pneumatic operators which close on loss of air to isolate the non-safety related portion from the safety related portion, which provides cooling to components supporting safe shutdown.
- The CCW heat exchanger temperature control valves fail open on loss of air and are controlled by remote manual means to support plant operation.
- Pneumatically operated valves in systems required for safe shutdown (e.g., shutdown cooling, CCW, intake cooling water) will fail in the position required for system operation in the plant shutdown mode. Except for the ADVs which fail closed, valves which are in required flow paths will fail open on loss of instrument air. The ADVs may be opened by local manual means in the event of loss of air.
- Valves which isolate nonessential portions of the system from portions required for safe shutdown fail closed. Pressurizer spray valves fail closed on loss of instrument air. Therefore, the loss of instrument air will not interfere with the safe shutdown of the plant on the onset of the SBO event.

EPU does not affect the fail-safe positions of air-operated valves or alter the controls of required equipment for safe shutdown. EPU has no effect on the capability of instrument air compressors to be manually loaded onto the vital bus. Therefore, the compressed air system is unchanged due to EPU conditions during the SBO event.

5. Effects of Loss of Ventilation

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

Reactor Containment Building

Inside containment, the primary impacts of loss of ventilation during the SBO event are increases in pressure and temperature caused by assumed RCS leakage and an increase in EPU decay heat.

The reactor containment building is analyzed for impact caused by loss of ventilation because of its safety significance. NUMARC 8700 assumes containment temperatures and pressures resulting from loss of ventilation inside the containment are enveloped by LOCA and high energy line break (HELB) environmental profiles. Since safe shutdown equipment is qualified for the accident environments under the plant's electrical equipment qualification (EEQ) program, operation during the less severe EPU SBO event is assured.

As indicated in UFSAR Section 6.2.1.2, the heat-up and pressurization of the containment during the SBO event is a function of the RCS leak rate. The original St. Lucie Unit 1 analysis considered an initial total RCS leakage rate of 120 gpm (RCS leakage allowed by TS plus RCP seal leakage; the leakage is pressure dependent and therefore decreases with decreasing RCS pressure. This is consistent with the current SBO reactor coolant inventory analysis provided in UFSAR Section 15.2.13. New analyses have been performed for 60 gpm of total leakage (Refer below to Subsection 7, Reactor Coolant Inventory, for additional details.). This leakage reduction is based on NRC-approved WCAP-16175-P-A (References 4 and 5), which documents improved RCP seal performance during loss of seal cooling conditions. Since the mass and energy released into containment in the original analysis is significantly larger than the EPU analysis, the original LOCA and HELB environmental profiles remain valid for the EPU. Therefore, the operability of equipment needed for safe shutdown inside containment is acceptable for the SBO event under EPU conditions.

Areas Outside Containment Containing SBO Equipment

Outside of containment, the control room, the electrical equipment areas (switchgear, static inverter, and battery rooms), the charging pump cubicle, and the AFW pump area were determined to contain equipment needed to achieve safe shutdown during the SBO event. Evaluations reported in Attachment 8 determined the maximum area temperatures attained during the first hour of the SBO event at current plant conditions. Calculated temperatures are shown to be acceptable.

The EPU does not impact the consequences of loss of ventilation in areas housing equipment required to achieve hot shutdown conditions during the SBO event.

6. Containment Isolation

During the SBO event, it is important to maintain appropriate containment integrity, which includes the capability for valve position indications and closure of certain containment isolation valves independent of Class 1E power supplies. Attachment 8 identifies the containment isolation valves reviewed and justifies their exclusion from consideration based on NUMARC 8700 criteria. The conclusions reached in Attachment 8 do not change as a result of EPU conditions.

As part of the EPU, remotely-operated containment isolation valves are proposed to be added to allow online containment purge. The valves are three-inch diameter, normally closed, air-operated, and designed to fail close on loss of instrument air or power. These valves also meet the isolation valve exclusion criteria in NUMARC 8700. Other than the addition of these valves, the EPU does not change the response of any containment isolation valves or the method of isolation utilized. Therefore, containment integrity remains unchanged during the SBO event under EPU conditions.

7. Reactor Coolant Inventory

During the SBO event, it is important to assure that the core remains cooled. RCS coolant inventory is potentially lost through normal RCS leakage, RCP seal leakage, and normal letdown operation. The results of the analysis described in the UFSAR Section 15.2.13 demonstrate that St. Lucie Unit 1 can successfully withstand the SBO event for at least four hours assuming a total leakage of 120 gpm.

EPU LAR Attachment 8 updates the pre-EPU CLB RCP seal leakage, making use of test data specific to the RCP seals. The test was run for 100 hours without seal cooling, and the maximum seal leakage measured during this period was less than 0.3 gpm per pump. The test results are provided in Section 7.2.1 (page 7-4) of the NRC-approved WCAP-16175-P-A.

The letdown line is automatically isolated upon loss of power and does not contribute to a reduction in reactor coolant inventory.

The ability to cope with the SBO event has been evaluated at EPU conditions in LAR Attachment 8, Appendix B. The EPU analysis assumes a 60-gpm leakage rate comprised of total RCP seal leakage of 40 gpm (10 gpm per RCP) plus a conservative assumption of 20 gpm to account for and bound TS allowed RCS leakage. The evaluation indicates that, at the end of a four-hour SBO event, core cooling is maintained, sufficient liquid inventory remains in the vessel to ensure that the core does not uncover, and no fuel failure is imminent. To achieve this result, an operator action has been credited to ensure the start of a charging pump at one hour upon availability of the AAC power source. This action is included in the existing emergency operating procedure (EOP) for managing a station blackout, but is not credited in existing analyses.

8. Auxiliary Feedwater Flow

During the SBO event, it is essential to maintain SG feedwater inventory to remove sensible and decay heat from the reactor core. The TDAFW pump is credited with supporting the decay and sensible heat removal from the core during the SBO event. At inception of the SBO event, the TDAFW pump receives an actuation signal on low level and is credited with delivering 600 gpm to two SGs within 330 seconds and feedwater continues throughout the coping period of four hours.

With respect to maintaining SG inventory, an operator action has been credited for the SBO event as a result of the EPU. Operator action is credited with ensuring that SG blowdown is isolated on loss of instrument air pressure. This action is included in the existing EOPs, but is not credited in existing analyses.

Steam turbine controls will remain unchanged due to EPU conditions. Therefore, the TDAFW pump will deliver adequate AFW and will be successfully controlled throughout the four-hour coping period for SBO during EPU conditions.

9. Plant Procedures and Training

There are no changes to procedures or training as a result of the EPU. Although the SBO analysis for EPU conditions now credits operator actions for ensuring that steam generator blowdown is isolated and starting a charging pump, these actions are already included in the EOPs.

10. Modifications Required to Cope with Station Blackout

No modifications are necessary for St. Lucie Unit 1 to cope with the SBO event under EPU conditions.

11. Quality Assurance

St. Lucie Unit 1 plant equipment originally classified as safety-related and required for SBO coping is covered by the 10 CFR 50, Appendix B Quality Assurance Program, which meets or exceeds the guidelines of Appendix A of RG 1.155,. No change to the Quality Assurance Program is required due to EPU for the SBO event.

12. Technical Specifications

As indicated above, the current TS Section 3.7.1.3 states that the CST shall be operable with a minimum usable volume of 116,000 gallons. Although it is not being revised as a result of the EPU SBO analysis, a revision to TS 3.7.1.3 is proposed to increase the minimum contained volume to 153,400 gallons to provide sufficient cooling water for the EPU operating conditions (LR Section 2.5.4.5). The EPU does not affect any other TS as related to the SBO event.

13. EDG Reliability Program

This program is unaffected by the EPU. The EDGs are not included among planned EPU modifications; therefore, the EDG Reliability Program remains unchanged by the EPU.

14. License Renewal

As discussed above, the systems required to mitigate the SBO event are within the scope of license renewal. Operation of the systems required to mitigate the SBO event 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.

2.3.5.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the plant's ability to cope with and recover from the SBO event for the period of time established in the plant's licensing basis. FPL concludes that the effects of the proposed EPU on the SBO event have been adequately evaluated and that the plant will continue to meet its licensing basis with respect to the requirements of 10 CFR 50.63 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. NUMARC-8700, Rev 0, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, November 20, 1987.
4. Topical Report WCAP-16175-P-A, Model For Failure of RCP Seals Given Loss Of Seal Cooling In CE NSSS Plants, revision 0 dated 02/12/2007, TAC No. MB5803 (ML070240429)
5. H. K. Nieh (NRC) letter to G. Bischoff (Westinghouse Electric Company), Final Safety Evaluation for Pressurized Water Reactor Owners Group (PWROG) Topical Report WCAP-16175-P, Revision 0, (CE NPSD-1199, Revision 1) “Model for Failure of RCP Seals Given Loss of Seal Cooling in CE NSSS Plants” (TAC No. MB5803), February 12, 2007.

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 (I&C) 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.

FPL 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) and 10 CFR 50.55a(h).

- 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 (AOOs), 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 AOOs 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 Standard Review Plan (SRP) Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the design relative to the GDC is discussed in UFSAR Section 3.1.

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 seismic Class 1. 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 Topical Quality Assurance 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-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.

- 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. In addition, instrumentation is provided for continuous automatic monitoring of process radiation level in the reactor coolant system (RCS).

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 are used to monitor the fission process. There are four startup channels, four safety channels, two control channels and two Appendix R channels;

b. Two independent control element assemblies (CEAs) position indicating systems;

c. A boron dilution alarm, which provides an alarm when a boron dilution event is in progress, is provided as a backup to the primary 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 reactor coolant boron concentrations.

Incore instrumentation is provided to supplement information on core power distribution and to provide for calibration of out-of-core 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 is designed to monitor the reactor operating conditions and to produce a reliable and rapid reactor trip if any one or a combination of conditions, deviate from a pre-selected operating range.

The containment pressure and radiation instrumentation is designed to function during normal operation and the postulated accidents.

The I&C 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 whole body, or its 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.

Following proven power plant design philosophy, 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 abnormal conditions. Shielding is designed to maintain tolerable radiation exposure levels following design basis accidents. The control room will be isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system is designed to recirculate control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 12.2. 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 reactor protective system 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 deenergizing the control element drive mechanism (CEDM) holding latch coils through the interruption of the 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 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. 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 inservice testability by designing to the requirements of IEEE 279-1971 and IEEE 338-1971. No single failure will result in the loss of the protection function. The protection channels are independent with respect to sensors and power supplies, piping, wire routing and mounting. This independence permits testing without loss of the protection function.

Each channel of the protection system, including the sensors up to the final actuation device, is capable of being checked during reactor operation. 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 7.2.2 and 7.3.2.

- 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 the Institute of Electrical and Electronic Engineers (IEEE) Criteria for Protection Systems for Nuclear Power Generating Stations, IEEE 279-1971. Four independent measurement channels complete with sensors, sensor power supplies, signal conditioning units and bistable trip units are provided for each protective 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.

UFSAR Section 7.2, describes the design criteria for the reactor protection system (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 and provides a description of the operation, actuation and isolation signals, redundancy, Instrumentation and control.

UFSAR Section 7.4 describes the I&C 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 requirements of Regulatory Guide (RG) 1.97, monitoring or post-accident condition, display instrumentation safety-related display instrumentation table.

UFSAR Section 7.6 includes a description of those systems which are required for safety which have not been discussed in UFSAR Sections 7.2 through 7.5. These systems include instrumentation to prevent overpressurization of the RCS and low pressure systems and to prevent or mitigate the consequences of possible refueling accidents.

UFSAR Section 7.7 describes the I&C systems whose functions are not essential for the safety of the plant and includes the plant instrumentation and control equipment not addressed in UFSAR Sections 7.1 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 St. Lucie Unit 1 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 System 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 NSSS design values from LR Section 1.1, Table 1.1-1.

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. The Containment Sump Recirculation actuation is addressed in LR Section 2.6.5, Containment Heat Removal.

As discussed in LR Section 2.13, Risk Evaluation, a risk informed change to the low SG 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% to ≥ 35% 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 SG 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 to accommodate loop uncertainty. The UA and the TS trip setpoint are combined in the safety analysis to establish the analytical limit. 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:

$$\text{TLU} + \text{ST} \leq \text{UA}$$

The EPU safety analyses were performed using updated analytical limits that contain allowances equal to or exceeding the UA. No changes were necessary for any RPS and ESFAS TS setpoints beyond the low SG 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
- 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; and
- 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 10.1),
- Circulating water system (UFSAR Sections 10.4 and 9.2),
- 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 and 10.4),
- Turbine generator system (UFSAR Section 10.2),
- Extraction steam system (UFSAR Section 10.3),
- Steam generator blowdown system (UFSAR Section 10.4),
- Fuel pool system (UFSAR Section 9.1), and
- Intake cooling water (service water) and ultimate heat sink system (UFSAR Sections 9.2 and 7.4).

The EPU evaluation of BOP I&C demonstrated that, except as noted below, the design of BOP instruments, ranges, and setpoints remain acceptable for EPU operation.

The existing indicated spans for indicators located at the hot shutdown panel in the reactor auxiliary building for monitoring steam line pressure, SG level, and SG wide range level as identified in UFSAR Section 7.4.1.8, are unaffected at EPU conditions.

The existing indicated spans for instruments required to monitor safe shutdown for the component cooling water (CCW) system, intake cooling water (ICW) system, auxiliary feedwater (AFW) system and atmospheric dump system as identified in UFSAR Table 7.4-1, 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 7.5-2. The existing indicated 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:

- Main steam line pressure,

- AFW pump discharge flow, and
- Condensate storage tank level.

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, 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. RCS damage caused by high system pressure,
2. Fuel rod cladding damage caused by a departure from nucleate boiling (DNB), and
3. Fuel centerline melt (FCM) 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 DNB or FCM with all reactor coolant pumps (RCPs) in operation.

Additional primary trip functions occur on high pressurizer pressure, low reactor coolant flow, low SG pressure, low SG water level, high SG pressure difference, high containment pressure, loss of turbine – low hydraulic fluid pressure, 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 SG pressure difference (asymmetric SG 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 Combustion Engineering (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 change 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 SG water level trip setpoint from ≥ 20.5% to ≥ 35% water level for each SG 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. 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.

The current design basis operational transients described in UFSAR Section 7.7.1 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% 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 SBCS being implemented.

Turbine First Stage Pressure Instrumentation

When the turbine generator is on line, turbine first stage pressure increases essentially linear from 0%–100% 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% and 100% reactor power. The current 0%–100% turbine load turbine first stage pressure correlates to 0–521.4 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%–100% power nominal first stage turbine pressure of 0–736.7psig. 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%–100% T_{avg} program reference value (T_{ref}) derived from 0–100% 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% power turbine first stage pressure range of 0–736.7 psig corresponds to the new T_{avg} range of 532–577°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 T_{avg} temperature program has changed for EPU, the nominal pressurizer level program temperatures for the low and high level limits have changed for EPU. The low limit T_{avg} setpoint is at 15% power temperature of T_{avg} 538.7°F. The high limit T_{avg} setpoint is at a temperature between 90% power T_{avg} temperature of 572°F. The level control program is linear between 15% power T_{avg} and the high limit T_{avg}. For measured T_{avg} below 15% 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, Plant Operability.

Feedwater Regulating System Changes

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 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 SG 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, Plant Operability.

Steam Bypass Control System Changes

The SBCS is comprised of five valves, one bypass valve and four dump valves, which dump steam to the condenser. For EPU, the capacity of the steam dump and bypass valves is being increased. Therefore, changes to the valve demand programs within the SBCS control logic are required. In addition, the setpoint for the large load rejection permissive signal was reduced, which allows the system to respond in a valve quick open mode of operation (rather than valve modulation mode) to improve the overall transient response. Minor changes were also made to the master valve controller output signal tracking logic to provide a smoother transition back to steam pressure modulation control following an initial SBCS quick open response to a large load rejection event. The evaluation of the steam bypass control system is described in LR Section 2.4.2, Plant Operability.

Containment Venting

The containment hydrogen purge system will be upgraded to provide capability for online venting, which will support a decreased TS Limiting Condition for Operation (LCO) for allowable containment pressure. The existing containment hydrogen purge system manual containment isolation exhaust valves will be upgraded to provide remote-manual control capability, and they will automatically close on a containment isolation signal. Open/close valve position indication will be provided in the control room.

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 input 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, Condensate and Feedwater. As a result of this evaluation, the following modifications will be implemented:

To regain operating margin when the EPU occurs on the main feedwater system, the following setpoints will be changed:

- 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; and
- 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. 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. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

Condenser and Circulating Water System

The condenser and circulating water system evaluation is described in LR Section 2.5.5.2, Main Condenser. As a result of this evaluation, the following modification will be implemented:

- Adjust condenser low vacuum alarm setpoint.

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 indicating switches.

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 I&C 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 RCPB 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 low SG water level trip setpoint from ≥ 20.5% to ≥ 35% water level for each SG 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 steam bypass control system 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, Plant Operability.

2.4.1.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the functional design of the reactor trip system, engineered safety feature actuation system, 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 thermal power	3020.0 MWt
Reactor coolant pump power	14.6 MWt
Pressurizer system pressure	2250.0 psia
Pressurizer level at full power	65.6%
Full power hot leg temperature	601.8°F
Full power cold leg temperature	551.0°F
Zero power cold leg temperature	532.0°F
Full power steam generator pressure	856.0 psia
Full power feedwater temperature	436.0°F

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). 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 & Light (FPL) conducted an evaluation of the NSSS I&C systems response to operational transients at extended power uprate (EPU) conditions to ensure that the responses remain acceptable.

The acceptance criteria are based on:

- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for the 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. In addition, instrumentation is provided in the letdown line for continuous automatic monitoring of the process radiation level in the reactor coolant system (RCS).

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:

a. 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.

b. Two independent control element assembly (CEA) position indicating systems

c. A boron dilution alarm, which provides an alarm when a boron dilution event is in progress, is provided as a backup to the primary method of determining soluble poison concentration by sampling and analysis of reactor coolant water.

d. Control of reactor power by means of CEAs

e. 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 (RPS) 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 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.

The reactor is controlled by reactivity adjustments with CEAs and with boric acid dissolved in the reactor coolant. Rapid changes in reactivity are compensated for, or are initiated by, CEA movement. Long term variations in reactivity due to fuel burnup and fission product concentration changes are controlled by adjusting the boric acid concentration.

UFSAR sections that address the design features and functions of the instrumentation and controls of the reactor protection systems include:

- The design bases, criteria, safety guides, information guides, standards, and other documents that are implemented in the design of the systems listed in UFSAR Section 7.1.1 are included in the subsections describing each system. (Refer to UFSAR Sections 7.2 through 7.6).

- The RPS is designed to assure adequate protection of the fuel, fuel cladding and RCPB during anticipated operational occurrences. Those NSSS conditions which require protective system action are discussed in detail in UFSAR Chapter 15.
- The ESF are described in three functional subdivisions in the UFSAR. UFSAR Section 7.3.1.1 describes the protective action provided by the ESFAS. The actuation signal includes all equipment from the initiating sensor through the contact of the output relays. UFSAR Section 7.3.1.2 describes the instrumentation and control of the ESF that are not part of the actuation signal. The instrumentation and control of supporting systems to the ESF are discussed in UFSAR Section 7.3.1.3.
- Safety-Related Display Instrumentation (Includes Non-Safety-Related Display Instrumentation), are those instrumentation systems which provide timely information to the operators to enable them to observe safety-related and non-safety-related parameters and take the appropriate action. Safety-related display instrumentation include the following:
  a. RPS monitoring (1E)
  b. ESF monitoring (1E)
  c. CEA position indication (non 1E)
  d. Boron control display instrumentation (1E and non-1E)
  e. Plant process display instrumentation (1E and non-1E)
  f. Control Boards (1E) and Annunciators (non-1E)
- The control and instrumentation systems whose functions are not essential for the safety of the plant includes all of the plant instrumentation and control equipment not addressed in UFSAR Sections 7.1 through 7.6.

In addition to the licensing basis described in the UFSAR, plant operability as it relates to I&C systems was evaluated for St. Lucie Unit 1 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. and UFSAR Chapter 18.

2.4.2.2 Technical Evaluation

2.4.2.2.1 Introduction

UFSAR Sections 7.7.1.1 and 7.7.1.3.2 identify the plant's ability to sustain the following operational transients:

A step increase in steam flow of 10%, with the steam flow initially between 15 and 90%.

A step decrease in steam flow of 10%, with the steam flow initially between 100 and 25%.

Ramp changes in steam flow at a rate of 5% per minute within the range of 15 to 100%.

A load rejection of up to 29% with steam bypass control system (SBCS).

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 St. Lucie Unit 1 at the EPU conditions. The transients specified above were analyzed to show that the plant response is acceptable. The transients evaluated included transients starting from 90% 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 trim 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 RCS reference temperature for 100% 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% flow setting for the 15% 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 RPS and ESFAS setpoints. The RPS and ESFAS setpoints used are:

High pressurizer pressure reactor trip:	2397.5 psia
Pressurizer minimum thermal margin low pressure reactor trip:	1887.0 psia
Low pressurizer pressure safety injection (SI):	1612.5 psia
Low SG pressure reactor trip:	626.1 psia
Low SG pressure main steam isolation signal (MSIS):	615.0 psia
Low SG narrow range level reactor trip:	35.5%
Low SG narrow range level auxiliary feedwater actuation signal (AFAS):	19.5%

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%, with the steam flow initially between 15 and 90%

A 10% step increase in steam flow was evaluated from initial power levels of 25%, 50%, 80% and 90%. No operator actions were assumed and CEA control was in manual.

A step decrease in steam flow of 10%, with the steam flow initially between 100 and 25%

A 10% step decrease in steam flow was evaluated from initial power levels of 25%, 50%, 90% and 100%. No operator actions were assumed and CEA control was in manual.

Ramp changes in steam flow at a rate of 5% per minute within the range of 15 to 100%

A ramp change in steam flow from 100% to 15% 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% power, a condensate pump at about 45% power and both heater drain pumps at approximately 35% power.

A ramp change in steam flow from 15% to 100% 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% power, a main feedwater pump one minute later and the heater drain pumps at approximately 80% power.

A load rejection of up to 29% with SBCS

A 30% step decrease in steam flow with SBCS was evaluated from initial power levels of 75%, 90% and 100%. The 30% step decrease in steam flow bounds the identified 29% 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% and 100%. Also turbine trip with reactor trip on turbine trip was evaluated from power levels of 25%, 50%, 75%, 90% and 100%.

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 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%, with the steam flow initially between 15 and 90%

A 10% step increase in steam flow was evaluated from initial power levels of 25%, 50%, 80% and 90%. The minimum pressurizer pressure was 2143 psia. The minimum SG pressure was 749 psia which is 122.9 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% for EPU is acceptable.

A step decrease in steam flow of 10%, with the steam flow initially between 100 and 25%

A 10% step decrease in steam flow was evaluated from initial power levels of 25%, 50%, 90% and 100%. The maximum pressurizer pressure was 2349 psia which is 48.5 psi below the reactor trip setpoint. The maximum pressurizer pressure occurred at 100% power level (EPU condition) which is an increase of 5 psia above the 90% power level. The SBCS valves open to limit the increase in secondary pressure. The maximum SG pressure was 935 psia which is 65 psi below the nominal main steam safety valve (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% for EPU is acceptable.

Ramp changes in steam flow at a rate of 5% per minute within the range of 15 to 100%

Ramp changes in steam flow from 100% to 15% power and from 15% to 100% power were evaluated. The results obtained were bounded by the 10% 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% per minute for EPU is acceptable.

A load rejection of up to 29% with SBCS

A 30% step decrease in steam flow was evaluated from initial power levels of 75%, 90% and 100%. The maximum pressurizer pressure was 2348 psia which is 49.5 psi below the reactor trip setpoint. The maximum pressurizer pressure occurred at 100% power level (EPU condition) which is an increase of 2 psia above the 90% power level. The SBCS valves open to limit the increase in secondary pressure. The maximum SG pressure was 923 psia which is 77 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% 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% and 100%. Also turbine trip with reactor trip on turbine trip was evaluated from power levels of 25%, 50%, 75%, 90% and 100%. For these transients, the SBCS valves open to limit the increase in secondary pressure. For a reactor trip from 100% power level (EPU condition), the maximum SG pressure was 971 psia which is an increase of 19 psia from the 90% power level. For a turbine trip with reactor trip on turbine trip from 100% power level (EPU condition), the maximum SG pressure was 973 psia which is an increase of 20 psia from the 90% power level. 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, September 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. 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 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;
- 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 assure that safety is not significantly impaired.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the 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 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 7.7.1.2 describes the reactor coolant control system, which is comprised of two subsystems, the reactor coolant pressure control system and the pressurizer water 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 whole body, or its 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.

All 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.

- 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 cylindrical carbon steel vessel with stainless steel clad internal surfaces. A spray nozzle on the top head is used in conjunction with heaters in the bottom head to provide pressure control. Over pressure protection is provided by three safety valves and two PORVs.

Pressure is maintained by controlling the temperature of the saturated liquid volume in the pressurizer. At full load conditions, slightly more than one half the pressurizer volume is occupied by saturated water, and the remainder by saturated steam. In order to maintain the desired pressure, the corresponding saturation temperature must be maintained. To maintain this temperature, approximately 20% of the 120 installed heaters are kept energized to compensate for heat losses through the vessel and to raise the continuous subcooled pressurizer spray flow to the saturation temperature.

The pressurizer spray is supplied from two of the reactor coolant pump cold leg discharges to the pressurizer spray nozzle. 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 components are sized to use the differential pressure between the pump discharge and the pressurizer to pass the amount of spray required to prevent the pressurizer steam pressure from opening the power operated relief valves during normal load following transients.

The reactor coolant pressure control and pressurizer water level control systems operate to control pressurizer water level and pressure during plant steady-state operation and design basis transients.

At least 150 KW of heaters capable of being supplied from emergency power are required for pressurizer OPERABILITY as specified in Technical Specification 3.4.4. Instrumentation associated with pressurizer pressure measurement is addressed in UFSAR Section 5.6.2.1.

As described in UFSAR Section 5.5.3, the capacity of the PORVs has been selected to pass the maximum steam surge associated with a continuous control element assembly (CEA) withdrawal starting from low power. Assuming that a reactor trip is initiated on a high pressure signal, the capacity of the power operated relief valves prevents the opening of pressurizer safety valves. The total relief valve capacity is sufficient to prevent the safety valves from opening during a loss of load from full power.

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 St. Lucie Unit 1 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
- Pressurizer heaters

To support the EPU, new control system settings for the pressurizer level control program as a function of T_{avg} will be implemented as discussed in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. The pressurizer safety valves 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 5.5.2, and 7.7.1.2. 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 and Assumptions

Pressurizer PORVs

The PORVs are designed to pass the maximum steam release associated with a continuous CEA withdrawal starting from low pressure conditions. The total relief capacity shall be sufficient to prevent the safety valves from opening during a loss of load from full power.

The CEA withdrawal and loss of load analyses were performed following the general guidelines and methodology presently in use for Chapter 15 accident transient analyses and for plant operational transient evaluations. They were consistent with the following design parameters and assumptions listed below:

- Two Dresser valves - Model 31533VX-30 with an orifice bore area of 1.353 in^2
- Design temperature of 700°F
- Design pressure of 2485 psig
- Design capacity of 153,000 lbs/hr of saturated steam*
- Set pressure of 2400 psia
- Valve design backpressure of 500 psig
- Valve stroke time is 0.25 sec after circuit delay of approximately 1 sec

* 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 transient evaluations were consistent with the following design parameters and assumptions listed below:

- Two full capacity valves with a design flow of 375 gpm
- Design pressure of 2485 psig
- 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 control

Pressurizer Heaters

The design criterion for sizing the pressurizer heaters is that the heatup rate of the pressurizer with water level at the “zero power level” must match the heatup rate of the reactor coolant system with four reactor coolant pumps 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 transient evaluations were performed following the general guidelines and methodology presently in use. These were consistent with the following design parameters and assumptions listed below:

- Single unit direct immersion type with a total capacity of 1575 kW
- Minimum heater capacity of 1375 kW with 110 heaters out of 120 in operation.
- Approximately 20% of the heaters are connected to proportional controllers to account for steady state heat losses and to maintain steam pressure
- The remaining heaters are backup heaters energized on low pressurizer pressure signal

2.4.3.2.3 Description of Analyses and Evaluations

Pressurizer PORVs

The CEA withdrawal event at full power described in UFSAR Section 15.2.1.3 has a peak RCS pressure of 2363 psia using the PORV flow capacity of 306,000 lbs/hr.

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. Evaluation of the CEA withdrawal at power event can be found in LR Section 2.8.5.4.2. Evaluation of Loss of Load event can be found in LR Section 2.8.5.2.1, Loss of External Electrical 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 during 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% to 90% 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 to mitigate 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. The heatup maneuver is essentially the same as that which St. Lucie Unit 1 presently experiences.

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 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.

The current Chapter 15 accident transient analyses and the EPU Chapter 15 results both do not take credit for PORV actuation to mitigate the consequences of any accident.

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 for those transients. 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. This confirms the current design basis that during transients from power operating conditions the PORVs would not be subjected to water solid inlet conditions.

Pressurizer PORVs

The current design criteria is that the total PORV relief capacity shall be sufficient to prevent the pressurizer safety valves opening during a loss of load from full power. The result of the re-analysis of this event at EPU conditions, showed that the resulting system pressure would be 2489 psia, which is below the nominal safety valve setpoint of 2500 psia. This is acceptable because the analysis conservatively did not credit SBCS or a reactor trip on a turbine trip signal within the loss of load analysis. If either item had been credited in the analysis, the peak pressure would have been well below the pressurizer safety valve setpoint.

The uncontrolled CEA rod withdrawal event currently discussed in UFSAR Section 15.2.1.3 resulted in a maximum system pressure of 2363 psi. This transient was re-analyzed and the resulting pressure of 2385 psia maintains the margin to the PORV opening setpoint of 2400 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% to 90%, the pressure increase was limited to 2350 psia with full flow through the spray valves for approximately 17 seconds.

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 2.5 seconds into the transient, reaching full open at 6.1 seconds and the pressure increase was terminated at 6.3 seconds, below the safety valve setpoint.

Pressurizer Heaters

The plant margin to trip analyses discussed 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 the its current licensing basis with respect to the requirements of 10 CFR 50.55a(a)(1) and 10 CFR 50.55(a)(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 1 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% (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 St. Lucie Unit 1 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 1 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 4, respectively). The referenced topical reports and NRC approvals are as follows:

1. ER-80P, Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM Check System, dated March 1997.

2. ER-160P, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check System, dated May 2000.
3. 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:

a. ER-80P, NRC SER, dated March 8, 1999.

b. ER-160P, NRC SER, dated January 19, 2001.

c. 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 5 diameters upstream from the existing FW venturi and a minimum of 21 diameters downstream from the nearest 90 degree 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 degree 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 provides 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 1 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% 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. Contingency plans for operation of the plant with the LEFM CheckPlus system out of service are described in Section I.5.

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 1. St. Lucie Unit 1 currently uses venturis, differential pressure transmitters, and RTDs to obtain the daily calorimetric heat balance measurements. St. Lucie Unit 1 is installing a new LEFM CheckPlus system 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 1. The calibration factor for the St. Lucie Unit 1 flow elements has been established by tests of these spools at Alden Research Laboratory in February 2009. These tests included a full scale model of the St. Lucie Unit 1 hydraulic geometry and piping arrangement. Test data and results for the flow elements are documented in Cameron Engineering Report ER-733, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 1 (Reference 6). The calibration factor (also known as the meter factor) used for the St. Lucie Unit 1 flow elements and the uncertainty in the calibration factor for the LEFM CheckPlus system are also based on this Cameron engineering report. ER-733 (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-733. Final commissioning is expected to be completed at the conclusion of refueling outage SL1-24.

I.3 Rated Thermal Power Uncertainty Calculation

LR Table 2.4.4-1 summarizes the core thermal power measurement uncertainty for St. Lucie Unit 1 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-733, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 1 and ER-740, Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie Units 1 & 2 Using the LEFM checkplus System. ER-733 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 LR 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 St. Lucie Unit 1 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 0.0054% and 0.0173% for the 1A and 1B SGs respectively. The uncertainty of the MCO test results was calculated by test vendor to be 0.0029% and 0.0043% for the 1A and 1B 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%. In accordance with standard Cameron methodology, the MCO uncertainty term used in the overall LEFM calorimetric uncertainty analysis was based on an assumed 10% variation in the vendor warranty MCO value (i.e., the uncertainty term is based on 0.01%). Therefore, the basis of the MCO uncertainty term is substantially greater than the tracer gas test uncertainty and further, is almost as large as the actual combined moisture carryover (i.e., the average MCO of the two SGs is 0.011%).

I.4 System Maintenance

Instruments that affect the power calorimetric, including the LEFM CheckPlus system inputs, are monitored by St. Lucie Plant 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 are be trained and qualified per the St. Lucie Station Institute for Nuclear Power Operations (INPO) accredited training program before maintenance or calibration is performed and prior to increasing power above 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 St. Lucie I&C Training Program, and formally trained on the LEFM CheckPlus system.
- Reliability of the LEFM CheckPlus system is to be monitored by St. Lucie Station System 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 1 LEFM CheckPlus system will be included in Cameron's Verification and Validation Program, and procedures are maintained for user notification of important deficiencies. The LEFM CheckPlus system purchase agreement with FPL included requirements that Cameron inform FPL of any deficiencies in accordance with Cameron's maintenance agreement and/or 10 CFR 21 reporting requirements.

I.5 Out of Service Requirements

UFSAR Section 13.8, 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% 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%) 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% 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 13.8 will restrict plant power to less than or equal to 2968 MWt (based on 98.3% 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% during the 48-hour period, then power level will be restricted to less than or equal to 2968 MWt (based on 98.3% of the proposed licensed power level of 3020 MWt) until the LEFM CheckPlus system is fully functional. This immediate response following a 10% 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 system 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 13.8 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 1 configuration will include separate LEFM flow elements (spool pieces), one for each of the two FW headers. These LEFM subsystems (meters) function independently of each other to calculate a mass flow rate for each of the two FW headers. 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% uncertainty vs. 0.30% uncertainty with both sections of both meters operable. UFSAR Section 13.8 will include an Action Statement to specify that if either LEFM meter has experienced a failure of only one section (four paths) of the system, then plant power will be limited based on a total calorimetric uncertainty of 0.46%.
- The site-specific uncertainty analysis (Cameron ER-740) also documents a system level uncertainty of 0.50% for a postulated failure of one section in both LEFM CheckPlus meters. UFSAR Section 13.8 will include an Action Statement to specify that if both LEFM subsystems (meters) have experienced a failure of only one section (four paths), then plant power will be limited based on a total calorimetric uncertainty of 0.50%.
- 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 13.8 will specify those components that may be removed from service without any corresponding reduction in plant power.

If the 48-hour outage period is exceeded, then the plant will operate at a power level consistent with the accuracy of the alternate plant instruments. The Action Statement requirements for power reduction is 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%. 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%.

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%. The analysis results demonstrate compliance with the applicable analysis limit(s) at the EPU power level, including a measurement uncertainty of 0.3%.

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%. 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%.

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%. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3%.

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%. 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%.

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%. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3%.

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%. 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%.

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%. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3%.

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 Factors. 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 Plant Unit 1 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 Section I.5.

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 Section I.4.

Operator Actions

As discussed Section I.5, new Action Statements pertaining to various LEFM CheckPlus system failure modes and/or degraded conditions are to be added to UFSAR Section 13.8. 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 Section I.1.

Plant Simulator

Modifications to the plant simulator pertaining to operation of the Cameron LEFM CheckPlus system are discussed in Section I.1.

Modifications

Modifications required for the MUR are to be completed prior to increasing reactor thermal power above 2968 MWt (based on 98.3% 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 and 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%. Per existing procedures, steady state power is maintained between 99.92% and 99.97%. 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.
- 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, 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, 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, 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-733, Revision 3, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 1.
7. ER-80P NRC Safety Evaluation Report (SER), March 8, 1999.
8. ER-160P NRC Safety Evaluation Report (SER), January 19, 2001.
9. ER-157P NRC Safety Evaluation Report (SER), 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
Hydraulics (profile factor)	0.25%	0.20%[(2)]	0.40%	0.44%
Geometry (spool dimensions, transducer installation, spool thermal expansion)	0.09%	0.14%	0.16%	0.17%
Time measurements (transit times and non-fluid delay)	0.045%	0.045%	0.045%	0.045%
Feedwater density (correlation, LEFM temperature determination, pressure input)	0.07%	0.07%	0.07%	0.07%
Feedwater enthalpy (correlation, LEFM temperature determination, pressure input)	0.08%	0.08%	0.08%	0.08%
Steam enthalpy (pressure input)	0.07%	0.0225%	0.0225%	0.0225%
Steam enthalpy (moisture uncertainty)	0.21% [0.0%][(1)]	0.0087%	0.0087%	0.0087%
Other gains and losses (calorimetric related process parameters)	0.07%	0.0356%	0.0356%	0.0356%
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 0.22% for loop A and 0.29% 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 are protected from flooding. The FPL review covered flooding of safety-related structures, systems, and components from internal sources, such as those caused by failures of tanks and vessels. The FPL 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 acceptance criterion for flood protection is based on General Design Criterion (GDC)-2.

Specific review criteria are contained in Standard Review Plan (SRP) 3.4.1, and other guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See Licensing Report (LR) Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 1 are measured against the U.S. Nuclear Regulatory Commission (NRC) General Design Criteria for Nuclear Power Plants, Title 10 of the Code of Federal Regulations (10 CFR) 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the General Design Criteria is discussed in UFSAR Section 3.1.

The adequacy of St. Lucie Unit 1 design relative to conformance to:

- 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 (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 design basis earthquake (DBE). 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 DBE. 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 DBE.

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

Internal flooding was not a design basis event for the plant when the original GDCs were issued in 1967. Only external flooding and its consequences on plant safety had been required by GDC-2. The 1971 GDCs did not address internal flooding protection either, as one of the plant criteria to be used during the design phase of the plant. Criterion 2 of the 1971 GDCs addressed requirements to provide plant protection against natural phenomena, but only included externally-induced flooding protection.

The regulatory requirement for internal flooding design review is limited to the effects of a postulated fire main pipe rupture, contained in UFSAR Appendix 9.5A, Section 3.1.3.

NRC Generic Letter (GL) 88-20, Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f) (Reference 1) was addressed to all holders of operating licenses. FPL submitted "St. Lucie Units 1 and 2, Individual Plant Examination Submittal" (Reference 2). Section 3.6 of Reference 2 addresses Internal Flood Analysis. For a discussion of this evaluation, refer to LR Section 2.5.1.1.1.2.

Internal flooding from sources other than high energy line breaks and moderate energy line cracks is addressed in the following UFSAR sections:

- UFSAR Section 3.4.4, Flood Protection
- UFSAR Chapter 9.5A Subsection 3.1.3, ECCS Pump Room Flooding Analysis

In addition to the licensing basis described in the UFSAR, flood protection was evaluated for St. Lucie Unit 1 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 Chapter 18 of the UFSAR.

2.5.1.1.1.2 Technical Evaluation

2.5.1.1.1.2.1 Introduction

This LR Section addresses impact of the extended power uprate (EPU) on 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 LR Section 2.5.1.3, Pipe Failures.

Submergence inside containment is addressed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment.

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.

2.5.1.1.1.2.2 Description of Analyses and Evaluations

Flooding from Non-Seismic Tanks

As addressed in LR Section 2.5.1.1.1.1 above, the regulatory requirement for internal flooding design review is limited to the effects of a postulated fire main pipe rupture. Accordingly, the effects of internal flooding due to a catastrophic failure of all non-seismic tanks are not analyzed.

Internal Flood Analysis

The design basis flooding event outside containment is the postulated rupture of a fire main pipe. EPU does not impact the fire protection system. There are no changes to the fire protection system flow, pressure or piping. Therefore, EPU does not impact the potential for internal flooding from a postulated rupture of a fire main pipe.

As addressed in LR Section 2.5.1.1.1.1 above, FPL submitted Reference 2 to the NRC to address the Individual Plant Examination criteria for severe accidents that were issued to all nuclear plants in GL 88-20 (Reference 1). In this report, an internal flooding analysis was performed for structures outside containment. After a qualitative screening process was performed, the following areas (flood zones) were determined to be vulnerable to the effects of floods, and found to have the potential for contributing to the overall core damage frequency:

- Steam trestle/auxiliary feedwater pumps
- Intake cooling water
- Component cooling
- Condensate pump and condenser area/condensate pump pit
- Feedwater pumps 1A and 1B

- Aerated waste storage tank and main hallway east (El. 19.5 feet)
- Shutdown heat exchangers 1A and 1B
- Pipe tunnel
- 1A and 1B emergency core cooling system
- Holdup tank enclosure
- “AB” switchgear room
- “B” switchgear room
- Cable spreading room
- “A” switchgear room
- Resin addition tank
- Control room
- Component cooling water surge tank

These flood zones were defined as identical to the fire zones described in the fire protection analysis in UFSAR Chapter 9.5A. A zone-by-zone screening was performed utilizing a combination of plant drawing reviews, plant walkdowns, and review of previous internal flooding analyses. For screening purposes, a bounding flood and/or spray scenario was postulated within a zone. If it was concluded that the resulting flood level or spray could cause failure of a component(s), the effect of loss of the specific component(s) was then analyzed in terms of whether the affected component is associated with an initiating event and/or equipment relied upon to mitigate the consequences of an accident (probabilistic risk assessment [PRA] equipment).

2.5.1.1.1.2.3 Evaluation of 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

As addressed in LR Section 2.5.1.1.1.1 above, the regulatory requirement for internal flooding design review is limited to the effects of a postulated fire main pipe rupture. Accordingly, effects of internal flooding due to a catastrophic failure of all non-seismic tanks are not analyzed.

The design basis flooding event is the postulated rupture of a fire main pipe outside containment. EPU does not impact the potential for internal flooding from a postulated rupture of a fire main pipe.

The results of the internal flooding analysis (Reference 2) for structures outside containment, submitted to the NRC in response to GL 88-20 (Reference 1), concluded that there is no credible internal flood/spray scenario which provides a significant contribution to the overall risk of the plant.

The EPU does not affect the listing of flood zones that were addressed in the analysis contained in Reference 2. The EPU also does not add, change, or relocate any of the structures/components within these zones that would be associated with an initiating event and/or equipment relied upon to mitigate the consequences of an accident (PRA equipment). There is no increase in fluid volumes contained in tanks within the flood zones as a result of the EPU. Therefore, the internal flooding analysis, contained in Reference 2, performed in response to GL 88-20 remains valid at EPU conditions.

2.5.1.1.1.4 Conclusion

The regulatory requirement for internal flooding design review is limited to the effects of a postulated fire main rupture; internal flooding due to failure of tanks and vessels is not addressed. FPL has reviewed the analysis of internal flooding for structures outside of containment 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.

2.5.1.1.1.5 References

1. Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54 (f), November 23, 1988.

2. St. Lucie Units 1 and 2, Individual Plant Examination Submittal, Section 3.6 Internal Flood Analysis, Revision 0.

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 handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. FPL's 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 Extended Power Uprate (EPU) and that are not consistent with previous assumptions with respect to floor drainage considerations.

The acceptance criteria for the equipment and floor drains system are based on General Design Criterion (GDCs) -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), Section 9.3.3, and other guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See Licensing Report (LR) Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 1 are measured against the U.S. Nuclear Regulatory Commission (NRC) General Design Criteria for Nuclear Power Plants, Title 10 of the Code of Federal Regulations (10 CFR) 50, Appendix A, as amended through October 27, 1978. The adequacy of the St. Lucie Unit 1 design relative to the General Design Criteria is discussed in the UFSAR Sections 3.1.1 and 3.1.2.

The adequacy of St. Lucie Unit 1 design relative to conformance to

- 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 (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 design basis earthquake (DBE). 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 DBE. 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 DBE.

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.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, protection against dynamic effects associated with postulated rupture of piping, seismic design, and environmental qualification of mechanical and electrical equipment, respectively.

Leakage within the emergency core cooling system (ECCS) equipment room described in UFSAR Section 6.3.2 normally drains to the room, sump. From there it is pumped to the waste management system. Should a gross gasket failure or equipment failure occur which cannot be directly isolated, the spillage flows to the room sump. The sump pumps in each room will handle leakage for short periods of time. If leakages are greater than pump capacity or if gaseous radiation releases are greater than liquid waste system capabilities, the room is isolated. Room isolation is accomplished by stopping the pumps in that room and closing the sump isolation valve.

Functions and features of the equipment and floor drains system are presented in UFSAR Section 9.3.3, Equipment and Floor Drainage System

In addition to the licensing basis described in the UFSAR, the equipment and floor drains system was evaluated for St. Lucie Unit 1 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 Chapter 18 of the UFSAR.

2.5.1.1.2.2 Technical Evaluation

2.5.1.1.2.2.1 Introduction

This LR Section addresses impact of the EPU on the volume of leakage outside containment entering the equipment and floor drains system and on the potential for flooding due to backflow through the equipment and floor drains system, that might result from maximum flood levels, to areas of the plant containing safety-related equipment.

This LR Section also addresses impact of the EPU on system design to protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system.

2.5.1.1.2.2.2 Description of Analyses and Evaluations

Seismic Design

The sumps in the ECCS rooms have separate sump and leak detection instrumentation designed to seismic Class I requirements to enable the operator to identify which emergency core cooling system sump is filling and to initiate protective action as required. The remainder of the equipment and floor drains system serves no safety function, and is therefore not designed to seismic Class I requirements. The EPU does not affect seismic design of components in the equipment and floor drains system.

Expected Volume of Leakage

Section 9.3.3 of the UFSAR describes the equipment and floor drains system in the following St. Lucie Unit 1 structures:

- Reactor building
- Reactor auxiliary building

- 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 drains system. Therefore, the sizing of components within the existing equipment and floor drains system remains acceptable at EPU conditions.

Backflow Through the Equipment and Floor Drains System

The NRC issued Inspection and Enforcement (IE) Notice 83-044 (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 1. According to the review, safety-related equipment applicable to the IE Notice 83-044 is housed in the safeguards room of the reactor auxiliary building at elevation -0.5 feet. The two independent floor drainage systems within the St. Lucie Unit 1 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 1.

The EPU does not affect the design of the equipment and floor drains system in the reactor auxiliary building and therefore, does not affect the conclusions of the review performed in response to IE Notice 83-44.

Potential for Inadvertent Transfer of Contaminated Fluids to an Uncontaminated Drainage System

The equipment and floor drains system, as described in UFSAR Section 9.3.3, includes the following design features to prevent inadvertent transfer of contaminated fluids to an uncontaminated drainage system:

- Drainage in the reactor building is routed to the equipment drain tank or reactor drain tank.
- An alternate flow path is provided to return potentially radioactive leakage from the emergency core cooling system sumps in the reactor auxiliary building to the containment reactor drain tank in the event of a LOCA.
- The radioactive chemical waste from the radio chemistry laboratory, decontamination room, and sink in the sample room in the reactor auxiliary building is routed to the chemical drain tank.
- Potentially radioactive equipment and floor drains in the fuel handling building are routed by gravity flow to the reactor auxiliary building equipment drain tanks. Non-radioactive drains are routed to the outside together with roof drains.

The EPU does not add any new equipment or modify existing equipment in the equipment and floor drains system as described above and therefore, does not affect the existing system design features which prevent inadvertent transfer of contaminated fluids to an uncontaminated drainage system.

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 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.

2.5.1.1.2.2.4 Results

The EPU does not add any new equipment or result in changes in the seismic design of components in the St. Lucie Unit 1 equipment and floor drains system.

The EPU does not add any new equipment or modify existing equipment (e.g., pumps, strainers) in the St. Lucie Unit 1 reactor building, reactor auxiliary building, or fuel handling building that would result in increasing the quantities of liquids currently entering the equipment and floor drains system. Therefore, the sizing of the existing St. Lucie Unit 1 equipment and floor drains system 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 an event causing damage to safety-related equipment as a result of flooding related backflow through equipment and floor drainage system, as outlined in IE Notice 83-44 (Reference 1), could not occur at St. Lucie Unit 1. The EPU does not add any new equipment or modify existing equipment within the equipment and floor drains system in the St. Lucie Unit 1 reactor auxiliary building, and therefore does not affect the conclusions of the review performed in response to IE Notice 83-44.

There are no changes in the design or operation of the equipment and floor drains system in the reactor building, reactor auxiliary building, and fuel handling building as a result of EPU that would allow contaminated fluids to be inadvertently transferred to an uncontaminated drainage system.

2.5.1.1.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the equipment and floor drains 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 the quantities of liquids currently entering the equipment and floor drains systems, FPL concludes that the sizing of components within the existing equipment and floor drains system remains acceptable at EPU conditions. FPL concludes that the design of the equipment and floor drains system will (1) prevent the backflow of water to areas with safety-related equipment, and (2) ensure that contaminated fluids are not transferred to uncontaminated drainage systems following implementation of the proposed EPU. Based on this, FPL concludes that the equipment and floor drains 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 drains system.

2.5.1.1.2.4 References

1. IE Notice 83-044, 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, August 30, 1990.

2.5.1.1.3 Circulating Water System

2.5.1.1.3.1 Regulatory Evaluation

The circulating water system 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 circulating water system 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 extended power uprate (EPU). The acceptance criteria for the circulating water system are based on General Design Criterion (GDC)-4 for the effects of flooding of safety-related areas due to leakage from the circulating water system and the effects of malfunction or failure of a component or piping of the circulating water system 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See Licensing Report (LR) Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 1 are measured against the U.S. Nuclear Regulatory Commission (NRC) General Design Criteria for Nuclear Power Plants, Title 10 of the Code of Federal Regulations (10 CFR) 50, Appendix A, as amended through October 27, 1978. The adequacy of the St. Lucie Unit 1 design relative to the General Design Criteria is discussed in UFSAR Sections 3.1.1 and 3.1.2.

The adequacy of St. Lucie Unit 1 design relative to conformance to

- 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.

Structures, systems and components (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, protection against dynamic effects associated with postulated rupture of piping, seismic design, and environmental qualification of mechanical and electrical equipment, respectively.

Analysis of failures in the circulating water system at the intake structure and in the turbine building is addressed in UFSAR Section 10.1, Steam and Power Conversion System Summary Description.

In addition to the licensing basis described in the UFSAR, the circulating water system was evaluated for St. Lucie Unit 1 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, 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 the UFSAR, Section 10.1, failures in the circulating water system have been analyzed at the intake structure. The only safety-related components located on the intake structure are the intake cooling water pumps and the intake cooling water isolation valves between the essential seismic Class I headers of the intake cooling water system and the non-essential turbine cooling heat exchanger supply headers. Since the intake structure is an open deck structure with no internal compartments and since the intake cooling water pumps are located above the open deck, flooding damage to the pumps could not occur due to a rupture in the circulating water system. Water released on the deck would run off back to the intake canal or out onto the plant area. The header isolation valves are contained in a valve pit set into the deck of the intake structure. The valve pit has large drain openings which allow water entering the pit to drain off to the intake canal. Therefore, the valve pit cannot be flooded out due to circulating water system failures.

The only safety-related components in the turbine building are the main feedwater pump discharge motor-operated isolation valves, which are located approximately 5.5 feet above floor level. The turbine building is of open design and any internal flooding is designed to run out of the building and into the storm drains system. Therefore, flooding due to a rupture of the circulating water system within the turbine building will not affect the safety-related motor-operators of the feedwater pump discharge isolation valves. As addressed in the UFSAR, Section 10.1, spillage out from the turbine building into the plant yard poses no threat to the auxiliary feedwater pumps, which are located near the building, since the pumps and motors are elevated above plant grade.

Accordingly, the current analyses of flooding in the turbine building or intake structure remain applicable at EPU conditions, and internal flooding due to a circulating water system pipe break or expansion joint failure at EPU conditions will not affect safety-related equipment. The EPU does not affect the design or location of the turbine building or intake structure. As discussed in LR Section 2.5.8.1, Circulating Water System, the flow rate and operating pressures are unchanged at EPU conditions. There are no required modifications to the circulating water system, the turbine building, or the intake structure as a result of the EPU that would affect the analyses associated with 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 or intake structure, and does not add or relocate any safety-related equipment located outdoors and below grade elevation. Accordingly, the above analyses of flooding in the turbine building or intake structure remain applicable at EPU conditions, and internal flooding due to a circulating water system pipe break or expansion joint failure at EPU conditions will not affect safety-related equipment.

2.5.1.1.3.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As addressed above, 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, Circulating Water System, the flow rate and operating pressures are unchanged at EPU conditions. There are no required modifications to the circulating water system, the turbine building, or the intake structure as a result of the EPU that would affect the analyses associated with 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 or intake structure. 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 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, the turbine building, or the intake structure 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 evaluates missiles that could result from in-plant component overspeed failures and high pressure system ruptures. The FPL review of potential missile sources that could impact covered pressurized components and systems, and high-speed rotating machinery. The FPL 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 non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The FPL 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 acceptance criteria for the protection of safety-related SSCs against the effects of internally generated missiles that may result from equipment failures are based on

- GDC-4 insofar as SSCs 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 NUREG-0800, SRP Sections 3.5.1.1 and 3.5.1.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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.

  Conformance to the requirements of GDC-4 ensuring that safety-related SSCs are adequately protected from internally generated missiles is addressed in UFSAR Section 3.5.1.

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 3.5.2.1 addresses internal missiles generated from pressure containing components located inside of the reactor building, reactor auxiliary building, and diesel generator building. UFSAR Table 3.5-1 lists the spectrum of potential internal missiles, their kinetic energy, weights, leading cross-section configurations and the barriers designed to withstand them.

UFSAR Section 3.5.3.2.b addresses turbine missiles generated as a result of turbine rotor failure.

In addition to the licensing basis described in the UFSAR, the potential missile sources were evaluated for St. Lucie Unit 1 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 extended power uprate (EPU) on internally generated missiles that could result from in-plant component overspeed failures and high pressure system rupture have 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 Section 3.5 of the UFSAR.

The purpose of this review is to comply with the GDC-4 of 10 CFR 50, Appendix A 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 3.5.3.2b 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 SSCs that are necessary for the safe shutdown of the reactor or for accident mitigation or may cause damage to the SSCs 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 2.5.1.2.2, Turbine Generator, for evaluations of the impact of turbine missiles.

Refer to LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, for evaluation of pipe rupture locations and associated dynamic effects.

2.5.1.2.1.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal

As discussed above, the potential missile sources 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, 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.

2.5.1.2.1.2.4 Results

UFSAR Section 3.5.3.1 discusses potential missile sources and UFSAR Table 3.5-1 identifies specific missiles considered. The internal missiles identified in the UFSAR table are associated with the reactor coolant and main steam 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 SSCs, 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 SSCs with respect to internally generated missiles and will continue to meet the St. Lucie Unit 1 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.

2.5.1.2.1.3 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 proposed 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to the GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

St. Lucie Unit 1 specific GDC for the turbine generator is 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 demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

In addition to the licensing basis described in the UFSAR, the turbine generator system was evaluated for St. Lucie Unit 1 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) turbine in tandem with two double-flow low pressure (LP) turbines. 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 7.7.1.4. Upon occurrence of a turbine trip, 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 provided with two overspeed protection systems:

1. Overspeed Protection Controller (OPC) (see UFSAR Figure 10.2-1)

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 the turbine valves to trip if the turbine speed reaches 111.5 percent of rated speed.

2. Mechanical overspeed protection system (see UFSAR Figure 10.2-2)

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 the turbine valves.

The OPC system and the mechanical system do not share any sensing devices

A discussion and analysis of potential turbine missiles are provided in UFSAR Sections 3.5.2.2 and 3.5.3.2.

The two existing LP turbines will be replaced with new Siemens-supplied replacement turbines 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.

The current approach to LP turbine missile considerations, while acknowledging the extremely unlikely possibility of such an event, was based on providing adequate missile shielding or sufficient separation of redundant trains of safety-related systems to preclude missile interactions that would compromise the ability of the plant to safely shutdown. The possibility of HP turbine missiles was deemed non-credible based on the lack of sufficient energy of the rotor segments to penetrate the thick outer casing of the HP turbine structure.

Based on the complete replacement of the 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 the LP and HP rotors has been assessed and found acceptable. The following fundamental items 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.
- The Overspeed Protection Controller (OPC), the associated OPC solenoid valves, the emergency trip turbine trip solenoid valve and the mechanical overspeed trip device are planned to be replaced as part of an overall turbine control system upgrade to improve reliability and maintainability. The revised turbine control system will be provided by Westinghouse and will be based on a standard design previously installed for other US nuclear power plants. Two independent overspeed protection systems will be provided and each of these systems will include 2 out of 3 redundancy for speed sensing and turbine trip solenoid valve logic. These control system upgrades have 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 current turbine inspection frequency is well within the analyzed inspection interval used 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 2.58E-6 per year 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 5.40E-02 is unchanged by the EPU. Therefore, the probability of generating a destructive overspeed missile, which is taken as the product of the system separation and above conditional probability values, remains at a value of 1.39E-07/year under EPU conditions.
- Material properties of the replacement rotors along with their physical properties will be considered in the generation and growth of disk cracks and the potential generation and ejection of missiles originating from the failure of these new turbine disks in the evaluation of the EPU design condition.
- The turbine missile analysis and methodology used are in compliance with Reference 1 Topical Report, which was accepted by the NRC in the Reference 2 Safety Evaluation.

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 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 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 prohibit the generation of 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 EPU implementation and the original value is used in this analysis.

The existing digital electro-hydraulic control system monitors the turbine 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 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 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. 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 relies on the structural capacity of the building structures which house safety-related equipment, as well as, the separation of redundant trains of this equipment to adequately protect the reactor coolant pressure boundary, to prevent the public’s exposure to unacceptable radiological consequences and to maintain the ability to safely shut down the plant in the event of a turbine disk failure. 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 probability of missile generation be shown to be less than 1.0E-5/year in plants like St. Lucie Unit 1 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, St. Lucie Unit 1 utilizes a six month valve test frequency for the overspeed protection system along with a six year maximum inspection interval on the turbine rotors and blades to ensure a reasonably low probability of generating turbine missiles. Based on the St. Lucie Unit 1 turbine valve testing frequency and an analytically conservative 100,000 hour inspection frequency, the probability of generating a missile under the EPU design conditions was established as 2.52E-8/year. When this updated missile generation probability is added to the previously established destructive overspeed missile probability value of 1.39E-7/year based on a six month inspection interval, 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.

Refer to LR Section 2.13.1, Regulatory Evaluation, 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 Evaluation of 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.

2.5.1.2.2.2.4 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 1.645E-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.
- 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.

2.5.1.2.2.3 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.

2.5.1.2.2.4 References

1. TP-04124, Missile Probability Analysis for the Siemens 13.9m^2 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 & Light Company (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. FPL's review of pipe failures included high and moderate energy fluid system piping located outside of containment. FPL's review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analyses.

The NRC's acceptance criteria for pipe failures are based on:

- GDC-4, which requires, in part, that 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC's for the protection against postulated piping failures in fluid systems outside containment:

- 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 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 Class I seismic pipe which causes a 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 for details on missile protection, protection against dynamic effects associated with postulated rupture of piping, seismic design, and environmental qualification of mechanical and electrical equipment, respectively.

UFSAR Section 3.6 describes the design criteria and bases for protecting essential equipment from the effects of piping failures inside and outside of containment.

As stated in UFSAR Section 3.6.1, the analysis of high energy line breaks (HELBs) outside the containment is presented in UFSAR Appendix 3C for the main steam system and main feedwater system. UFSAR Appendix 3D presents the analysis of high energy line rupture outside of containment for all lines used for shutdown cooling (which includes portions of the low pressure safety injection system), chemical and volume control system (CVCS) (letdown and charging lines), steam generator blowdown system (SGBS), and the auxiliary steam system.

In addition to the licensing basis described in the UFSAR, the protective barriers associated with HELB were evaluated for St. Lucie Unit 1 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 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 or pressures greater than 275 psig (UFSAR Section 3.6.2).

The impact of the EPU on pipe whip and jet impingement considerations is discussed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects.

The Equipment Qualification Program (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 identifies systems in which design basis piping breaks are postulated to occur. The systems outside containment are:

- Main steam
- Main feedwater
- Chemical and volume control (letdown and charging lines)
- Steam generator blowdown
- Auxiliary steam
- Shutdown cooling/low pressure safety injection

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.

2.5.1.3.2.3 Evaluation of 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 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.

2.5.1.3.2.4 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 CVCS, SGBS, the shutdown cooling system (including portions of the low pressure safety injection system), or the auxiliary steam system.

The temperature and pressure effects associated with a main steam line break (MSLB) outside containment continue to be valid for the qualification of the essential equipment in the steam trestle area. An evaluation of temperatures resulting from high energy line breaks in the main feedwater system in the steam trestle area remain valid for EPU conditions.

The temperature and pressure effects associated with ruptures outside containment in the letdown or charging lines, SGBS lines, auxiliary steam lines and shutdown cooling lines including portions of the low pressure system injection system remain unchanged for EPU conditions.

The EPU does not affect the current evaluation of flooding in the auxiliary feedwater pump area due to a main steam or feedwater HELB. The EPU does not affect the potential for flooding safety-related equipment due to a HELB outside containment in the letdown and charging lines, SGBS, auxiliary steam system and shutdown cooling system (including portions of the low pressure safety injection system).

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 system lines commencing at the flued head anchor and terminating at the turbine stop valves. Similarly, the two main feedwater system 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, the EPU does not result in any new pipe break locations in the main steam or feedwater systems outside containment. No modifications to the main steam or feedwater piping outside containment are required as a result of the EPU.

The temperature and pressure effects associated with a MSLB outside containment are evaluated in LR Section 2.3.1, Environmental Qualification of Electrical Equipment.

An evaluation of temperatures resulting from high energy line breaks in the main feedwater system in the steam trestle area has been performed. The EPU does not affect the design conditions of the piping in which the breaks are postulated to occur. The piping operating temperature and pressure at EPU conditions are bounded by the operating temperature and pressure used in the feedwater high energy line break analysis. Therefore, the analysis results remain valid for EPU conditions.

Chemical and Volume Control System Outside Containment (Letdown and Charging Lines)

Maximum operating pressure and temperature for the charging line during normal operation is 2300 psig and 120°F, respectively. Neither the operating conditions in the charging line nor the charging pumps are affected by the EPU.

The temperature of the reactor coolant system (RCS) letdown flow entering the regenerative heat exchanger at EPU conditions is 551°F (RCS cold leg temperature – refer to LR Section 1.1, Nuclear Steam Supply System Parameters). Since this temperature is bounded by the temperature used in the HELB analysis (600°F), the temperature and pressure effects associated with a letdown line rupture at current conditions remain unchanged.

As addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, the EPU does not result in any new pipe break locations in the CVCS 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 SGBS lines outside containment are routed through and along the roof of the reactor auxiliary building. For the current analysis of a HELB in the SGBS, a pressure and temperature of 885 psig and 520°F, respectively, are used.

The maximum operating temperature of the steam generator blowdown system at EPU conditions is 520°F, and the system normal operating pressure at EPU conditions is 856 psia (approximately 841 psig). It is seen that the system maximum operating temperature at EPU conditions is the same as the current analysis temperature, and the system normal operating pressure at EPU conditions is bounded by the current analysis pressure. Therefore, the current analysis of a SGBS line break remains bounding for the EPU.

As addressed in LR Section 2.2.1, 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

For the current analysis of a HELB in the auxiliary steam system, the maximum operating pressure and temperature during normal operation are 885 psig and 520°F, respectively; various branch lines operate at lower pressures and temperatures.

The auxiliary steam system pressure and temperature at the main steam header connection at EPU conditions are 800.9 psig and 520.4°F. It is seen that the EPU pressure (800.9 psig) is bounded by the current analysis maximum operating pressure (885 psig), and the EPU temperature (520.4°F) is essentially the same as the current analysis maximum operating temperature (520°F). Therefore, the temperature and pressure effects associated with an auxiliary steam line rupture at current conditions remain unchanged at EPU conditions.

As addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated 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 are required as a result of the EPU.

Shutdown Cooling System (including portions of the Low Pressure Safety Injection System) Outside Containment

The limiting or worst case shutdown cooling line rupture is one which allows the greatest amount of reactor coolant to escape into the reactor auxiliary building, i.e., a rupture of a 12-inch line just at the onset of shutdown cooling. The system temperature and pressure conditions at this time are 300°F and 450 psig, respectively. (As noted in the UFSAR Appendix 3D, although the shutdown cooling system entry temperature has been increased to 325°F by the Technical Specifications, the increase in temperature does not increase the potential for loss of structural function.) The resultant area temperature and pressure rise, which are 50°F and less than 1 psig, respectively, have an insignificant effect on surrounding structures.

The shutdown cooling system (including portions of the low pressure safety injection system) operating conditions are not affected by EPU. Therefore, the temperature and pressure effects associated with a HELB in the shutdown cooling system (including portions of the low pressure safety injection system) at current conditions remain unchanged at EPU conditions.

As addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, the EPU does not result in any new pipe break locations in the shutdown cooling system (including portions of the low pressure safety injection system) outside containment. No modifications to the shutdown cooling system piping (including portions of the low pressure safety injection system piping) outside containment 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

Main Steam and Main Feedwater Systems Outside Containment

As addressed in the UFSAR Appendix 3C, there is no danger that a rupture of a main steam line or feedwater line could cause a loss of function of more than one auxiliary feedwater pump due to flooding. Each of the three pumps is provided with a flood wall around them to elevation +22 ft. The EPU does not affect the location of the auxiliary feedwater pumps or design of the flood walls surrounding the pumps. Therefore, the EPU does not affect the above evaluation of flooding in the auxiliary feedwater pump area due to a main steam or feedwater HELB.

As addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, the EPU does not result in any new pipe break locations in the main steam or feedwater systems outside containment. No modifications to the main steam or feedwater piping outside containment are required as a result of the EPU.

Chemical and Volume Control System Outside Containment (Letdown Line)

As addressed in the UFSAR Appendix 3D, there is no potential for flooding safety-related equipment since the volume of water involved is limited. Also, any leakage to the emergency core cooling system (ECCS) pump rooms is alarmed and isolable.

As previously indicated, the CVCS operating conditions continue to be bounded by the HELB analysis and are not affected by the EPU. Therefore, the EPU does not affect the potential for flooding safety-related equipment due to a HELB in the letdown line of the CVCS.

Steam Generator Blowdown System Outside Containment

As previously indicated, the temperature of the SGBS during normal operation is unchanged at EPU conditions, and the pressure during normal operation at current conditions bounds the pressure at EPU conditions. The EPU does not affect current blowdown system flow rates. Therefore, the EPU does not affect the potential for flooding safety-related equipment due to a HELB in the SGBS.

Auxiliary Steam System

As previously indicated, the auxiliary steam system pressure at EPU conditions (800.9 psig) is bounded by the system current maximum operating pressure (885 psig) and the temperature at EPU conditions (520.4°F) is essentially the same as the current maximum operating temperature (520°F). Therefore, the EPU does not affect the potential for flooding safety-related equipment due to a HELB in the auxiliary steam system.

Shutdown Cooling System (including portions of the Low Pressure Safety Injection System)

As addressed in the UFSAR Appendix 3D, a rupture in any portion of the shutdown cooling or low pressure safety injection system piping could directly or eventually drain to the ECCS pump rooms, which house safety-related equipment. However, these rooms are equipped with sumps which alarm in the control room on high level, which allows the operator to isolate all drain lines to that room or to shut off the source of the leak, or both.

As previously indicated, the shutdown cooling system (including portions of the low pressure safety injection system) operating conditions are not affected by EPU. In addition, the EPU does not affect the design of the equipment and floor drain system in the ECCS pump rooms. Therefore, the EPU does not affect the potential for flooding safety-related equipment due to a HELB in the shutdown cooling system (including portions of the low pressure safety injection system).

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 structures, systems, and components (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. FPL's review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that structures, systems and components (SSCs) required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire.

The NRC's acceptance criteria for the FPP are based on:

- 10 CFR 50.48 and associated 10 CFR 50 Appendix R, 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;
- 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 SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the Fire Protection Program 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 equipment are provided.

Normal fire protection is provided by sprinkler/spray or gaseous suppression systems, hose lines, and portable extinguishers. 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 water supply and water-based systems are provided with test hose valves for periodic testing. The 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.

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, Appendix 9.5A outlines how GDC-3 is met using the guidelines contained in Appendix A to BTP APCSB 9.5-1 and 10 CFR 50 Appendix R.

As stated in UFSAR Chapter 9.5A Section 2.3.2, a safe shutdown analysis has been performed in order to ensure that no single fire can prevent St. Lucie Unit 1 from achieving a safe cold shutdown. Conformance to the requirements of 10 CFR 50 Appendix R is discussed in UFSAR Chapter 9.5A Section 2.3.3.

Compliance of St. Lucie Unit 1 with the requirements of Appendix A to BTP APCSB 9.5-1 is addressed in UFSAR Chapter 9.5A Section 2.4.

The alternate shutdown methodology is discussed in UFSAR Chapter 9.5A Section 5.0.

As stated in UFSAR Section 9.5A, the FPP provides assurance, through a defense-in-depth design, that occurrence of a fire will not prevent safe plant shutdown functions and will not increase significantly the risk of radioactive releases to the environment. Fire prevention features are provided to prevent fires from starting; to detect rapidly, control, and extinguish promptly those fires that do occur; and to provide protection for structures, systems and components essential to shutdown so that a fire not promptly extinguished does not impair safe shutdown capability.

The Fire Protection License Condition is given in Paragraph 2.E of the Renewed Facility Operating License No. DPR-67, 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 by NRC letter dated July 17, 1984, and supplemented by NRC letters dated February 21, 1985, March 5, 1987, and October 4, 1988, 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 FPP implementation.

A Fire Protection Plan has been developed. As stated in Section 3.1 of the FPP, the Fire Protection Plan 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 also addresses fire protection policy for the protection of support facilities and non-safety-related SSCs. 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 St. Lucie Unit 1 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 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:

- Safe shutdown analysis
- 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 Section 2.5.1.4.2.3, Results.

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
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. The fire protection plant design features listed above will continued to meet their acceptance criteria as a result of the EPU.

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 exemption from 10 CFR 50 Appendix R requirements.

The impact of plant modifications being implemented in support of EPU (e.g., upgrade of main transformers with new coolers) on the FPP will be addressed in accordance with the plant change/modification process. The impact of EPU modifications on plant core damage frequency and large early release 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 evacuated 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. Alternate shutdown is accomplished in accordance with plant procedures.

The EPU does not modify 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 methods are provided for performance of the following functions:

- Reactor coolant inventory and pressure control can be maintained by the use of the chemical and volume control system (CVCS).
- Overpressurization protection for the primary system is provided by a pressurizer power operated relief valve (PORV) and the safety relief valves.
- Reactor decay heat removal in hot shutdown is provided through the steam generators by the auxiliary feedwater (AFW) system supplying water to the steam generators (SGs) from the condensate storage tank and the atmospheric dump valves (ADVs).
- In cold shutdown, the heat is removed by the shutdown cooling system and the ultimate heat sink.

Alternate 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 current design provides a minimum of one train of systems necessary to achieve and maintain safe shutdown conditions by utilizing either the control room or the alternative shutdown methods and thus meets the requirements of 10 CFR 50 Appendix R, Items III.G.3 and III.L with respect to safe shutdown in the event of a fire.

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 loss-of-coolant accident (LOCA) cannot result due to a single fire opening 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. Sampling system

c. Reactor coolant gas vent system

d. Shutdown cooling isolation

e. Power operated relief valves

The letdown line is provided with two pneumatic valves in series each of which is capable of isolating the reactor coolant system (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 the 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 redundant pneumatic valves which fail 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’ 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 eliminate the possibility of a LOCA through these lines.

A reactor coolant gas vent system is provided with redundant solenoid operated valves which fail closed on loss of power. Outboard valves are routed in dedicated conduits from the control room to penetration rooms precluding potential for spurious actuation due to fire induced hot shorts and are also provided with isolation switches allowing removal of power. These design features eliminate potential for a fire induced LOCA for any fires in the reactor auxiliary building. In the reactor containment, the power circuits of the outboard valves are routed utilizing dedicated armored cables therefore, eliminating potential for spurious actuation(s).

The RCS is isolated from the low pressure safety injection system by means of redundant motor operated valves. Each line has two valves in series, one valve powered by the SA Train and one by the SB Train. The power to these valves is removed during power operation. To eliminate potential for hot short energization (opening) of both valves in the same header, when the circuits are routed in raceways which are not appropriately separated, one raceway has a radiant energy shield installed (containment). Outside containment, routing of the power circuits for each pair of valves has been verified not to be subject to potential actuation due to one area fire.

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 relief valve has a motor operated valve located upstream for isolation. For diversity the relief valves 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 routing, armored cabling, transfer/isolation switches, radiant energy shields, etc., which combined assure that the potential for multiple spurious actuations leading to a loss of primary system integrity have been eliminated in areas where the cables are routed.

Under certain circumstances, a “B” train PORV is required to depressurize the primary system for the purpose of alternate shutdown. To insure that relief capacity is available for a shutdown outside control room an alternate power supply, transfer arrangement and HSCP controls are provided. Similarly, the associated block valve is provided with normal/isolate switch and HSCP controls. To assure same capacity for containment fires, tray separation and a combination of tray and conduit radiant energy shields assures that one train of PORV/PORV block will remain functional.

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

Administration 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, personnel qualification/training and fire protection system operability and surveillance requirements. The above topics are unaffected by the EPU. There are no required changes to the administrative controls for the fire brigade, fire prevention activities, fire protection systems and barriers, inspection and testing requirements, personnel qualification and training, fire protection system operability and surveillance requirements as a result of the EPU.

Safe Shutdown Analysis (SSA)

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.

Specific plant 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 the SSA are evaluated for impact of the EPU:

1. Cold shutdown time following reactor trip
2. Safe shutdown time line
3. Initial conditions for fire area analysis
4. Essential equipment list
5. Essential cable list
6. Circuit breaker coordination
7. Multiple high impedance faults
8. Associated circuits
9. Cable failure analyses
10. Operator actions required following a fire
11. Manual action timing

1. Cold Shutdown Time Following Reactor Trip

An analysis was performed at EPU conditions to demonstrate through analysis 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 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, Residual Heat Removal System, 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 shutdown cooling 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 reestablish 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. Once hot shutdown is reached, it is assumed that cooldown to cold shutdown is initiated.

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. The analyses 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. To meet 10 CFR 50 Appendix R Cold Shutdown (Mode 5) criteria, the shutdown cooling system, in conjunction with natural circulation cooldown of the RCS, must be able to achieve cold shutdown within 72 hours 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 safe shutdown or alternate shutdown procedures required to achieve and maintain cold shutdown.

3. 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.

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.

4. 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 lent 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 the electrically powered and indicated 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. 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.

5. Essential Cable List

After the essential equipment list was created, the cables required to allow essential equipment function was determined by review of the appropriate control wiring drawings (CWDs), one-line drawings, and power and distribution motor data drawings. This determination included the 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.

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.

6. <u>Circuit Breaker Coordination</u>

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. With the exception of the plant change discussed below under EPU conditions, protection devices for safe shutdown equipment are not changed or modified, and therefore the existing calculation is unaffected and coordination of protective devices is maintained. As addressed in LRSection 2.3.3, the electrical feeds for the heating and ventilation system fans 1-HVS-4A/4B are being changed fro 480V motor control centers to 480V load centers. Circuit breaker coordination for these circuits will be addressed in the plant modification process.

7. <u>Multiple High Impedance Faults</u>

Multiple high impedance faults from multiple circuits that trip the bus or 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 of wiring that will increase the possibility of occurrence of multiple high impedance faults.

8. <u>Associated Circuits</u>

The design of associated circuits (as defined for fire protection) is as follows:

Associated circuits are those that:

a. Have a physical separation less than that required by Section III.G.2 of Appendix R, and;

b. Have one of the following:

   1. 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

   2. A connection to circuits of equipment whose spurious operation would adversely affect the shutdown capability, or

   3. 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 Appendix R and have a common power source with safe shutdown equipment are provided with circuit breakers or fuses.

For circuits that do not meet the separation criteria of Section III-G.2 of 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.

The EPU does not introduce additional cables, change, modify, or add protective circuit devices or fire barriers; therefore, the existing analysis for associated circuits remains unchanged.

9. 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.

For fire zones/areas which are covered by an exemption, the description of the exemption as well as how the particular cable/situation meets the requirements as stated within the exemption is stated. In addition the exemption is referenced.

The EPU does not add, change or modify any fire zone/areas or NRC approved Appendix R exemptions. There are no electrical EPU changes or additions that will impact the circuit failure analyses.

10. & 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, and 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. 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.

Based on guidance in NRC Generic Letter 86-10, 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 (BAM) pump shutdown and CVCS 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 (CCW) 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 in 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 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. From an immediate EDG loading concern 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. To mitigate this condition an action time of 10 minutes has been assigned for these actions.

- Atmospheric dump valve isolation

  An analysis was prepared to determine the response to fire scenarios. Included in the scenarios evaluated is the assumption that an “A” Loop ADV is open for 60 minutes. Based on the results of the analysis, it is concluded that the RCS will not experience significant voiding when the ADV fails open for the period of 60 minutes. Additionally, the results of the conservative analysis show that the RCS always remains full up to the top of the hot/cold legs and core uncovery will not occur.

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
2. Heating ventilation and air conditioning (HVAC) considerations
3. Emergency core cooling system (ECCS) pump room flooding

1. <u>Instrument Sensing Lines</u>

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 sense lines remain valid under EPU conditions. Plant modifications being implemented in support of EPU will be reviewed in accordance with current plant procedures to ensure there are no adverse affects to the existing FPP including instrument sensing lines.

2. <u>Heating Ventilation and Air Conditioning Considerations</u>

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 introduce any new components, modify existing components, or add any heat loads that would affect the current evaluations of HVAC requirements for post-fire safe shutdown. Although the existing containment hydrogen purge system will be modified for EPU to allow on-line containment purge, the existing system is not required for safe shutdown equipment cooling or post-fire smoke removal at current plant conditions.

3. ECCS Pump Room Flooding

Evaluation of ECCS pump room flooding potential due to a fire main rupture is addressed in UFSAR Appendix 9.5A. The evaluation concludes that the design with regard to the ability to accommodate the fire main rupture is acceptable. The design complies with GDC-3 such that a failure of a fire main cannot 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 LOCA. Under EPU conditions there are no changes, modifications, or additions to plant equipment that will affect the current analysis.

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.

2.5.1.4.5 References

1. FPL Letter L-92-222, Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, Generic Letter (GL) No. 88-20, Supplement 4, August 31, 1992.

2.5.2 Pressurizer Relief Tank

2.5.2.1 Regulatory Evaluation

The pressurizer relief tank (PRT), referred to as the quench tank (QT), 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 is not safety-related and is not designed to accept a continuous discharge from the pressurizer.

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 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;
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles.

Specific review criteria are contained in SRP Section 5.4.11.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the PRT are as follows:

- 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 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 design basis earthquake (DBE). 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 DBE. 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 DBE.

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 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 Class I seismic pipe which causes a 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, 3.7.5, 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 (PORVs) and to prevent the discharge from being released to containment.

The QT is located lower than the pressurizer safety or relief valves to ensure that any leakage or discharge from the valves drains to the QT. The tank is designed and fabricated in accordance with the ASME Code Section III Class C.

The QT contains demineralized water under a 3 psig nitrogen overpressure. The sparger, spray header, nozzles and rupture disc fittings are stainless steel. The steam discharged into the QT from the pressurizer valves is discharged under water by the sparger to enhance condensation. The QT normal water volume of 127 cubic feet is needed to condense the steam released from the pressurizer safety and relief valves as a result of a loss of load followed immediately by an uncontrolled rod withdrawal with no coolant letdown or pressurizer spray. The tank gas volume is based on limiting the maximum tank pressure for this sequence of events to a value below the rupture disk set point and tank design pressure.

QT water level indication and high and low water level alarms are provided in the control room along with the pressure and temperature and acoustic indicators and alarms.

Leakage or discharge from the safety or relief valves is indicated and alarmed in the control room by temperature measurements in each valve pipe line to the QT header.

Evaluations beyond the requirements of ASME Code, Section III, include the tank head in accordance with Welding Research Council Bulletin #95. Compliance with this reference results in a tank head which is thicker than Section III design methods.

The seismic analysis of the QT ensures tank or support failures will not occur during a DBE and the natural frequency is greater than 20 cycles per second (cps) to preclude resonance. Besides these evaluations, the tank sparger is analyzed for both seismic forces and blowdown forces. These additional evaluations ensure that the QT will withstand these accident related conditions.

In addition to the licensing basis described in the UFSAR, the QT was evaluated for St. Lucie Unit 1 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 QT are within the scope of License Renewal. Programs used to manage the aging effects associated with the QT are discussed in SER Section 3.1 and Chapter 18 of the UFSAR.

2.5.2.2 Technical Evaluation

2.5.2.2.1 Introduction

The QT sizing analysis (primarily hand calculations), performed in 1968, 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 consistent with the guidance of 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, reevaluated the analysis of record (AOR) using limiting EPU design values for the Doppler coefficient, moderator temperature coefficient, and control element assembly (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 2.8.5.0, Accident and Transient Analyses.

Each of these event 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 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 546 pounds of steam for EPU. The bounding steam release for the uncontrolled rod withdrawal event evaluation for EPU was determined to be bounded by the 830 pounds of steam released in the AOR. The bounding steam releases for both events for EPU are lower than that of their respective AORs. 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 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 meet the requirements of GDCs -2 and -4. FPL finds the proposed EPU acceptable with respect to the design of the QT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

2.5.3.1.1 Regulatory Evaluation

The 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 SRP Section 6.5.3.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDCs is discussed in UFSAR Section 3.1.

Specifically, the adequacy of the fission product control systems and structures design relative to:

- 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.

On November 26, 2008, the NRC approved FPL's license amendment request regarding full-scope implementation of the alternative source term (AST) and issued Amendment No. 206 to the St. Lucie Unit 1 Operating License (Reference 1). UFSAR Section 15.4.1, Major Reactor Coolant System Pipe Break (Loss-of-Coolant Accident), was revised to incorporate the radiological consequence analysis associated with a LOCA utilizing the AST 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 15.4.1.5.2, Compliance with RG 1.183 Regulatory Positions. 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 Chapter 6 of the UFSAR 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 15.4.1-6. The shield building ventilation system (SBVS) is credited in the dose consequence analysis of a LOCA. The SBVS is credited 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: 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 (GL) 99-02, *Laboratory Testing of Nuclear-Grade Activated Charcoal.*

The iodine removal system (IRS) was added to the engineered safety features containment spray (CS) system as part of FPL's commitment to provide sufficient dose reduction in the LOCA event to meet the dose requirements at a low population zone (LPZ) distance of one mile as described in UFSAR Section 6.2.6. The IRS is also credited in the dose consequence analysis of a LOCA as shown in UFSAR Table 15.4.1-6.

In addition to the licensing basis described in the UFSAR, the fission product control systems and structures were evaluated for St. Lucie Unit 1 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 - Containment Spray, 2.3.3.15 - Ventilation, and 2.4.1 - Containments of the SER identifies 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 Chapter 18 of the UFSAR.

2.5.3.1.2 Technical Evaluation

The IRS is designed to operate in conjunction with the CS system to remove radioiodines from the containment atmosphere following a LOCA. It does this by injecting chemicals into the CS pump suction lines during CS operations to control pH and for iodine absorption. The IRS is in essence a subsystem of the CS system. The CS system removes heat from the containment by spraying a borated water and sodium hydroxide 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 CS system consists of two redundant 100 percent capacity subsystems each consisting of a CS pump, shutdown heat exchanger and spray header. The IRS is described in Section 6.2.6 of the UFSAR.

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 Section 6.2.3 of the UFSAR for a discussion of the SBVS.

LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST) 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, Engineered Safety Feature Atmosphere Cleanup 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, Primary Containment Functional Design 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 CS 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 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.

2.5.3.1.4 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 CS system including the IRS, and the SBVS to perform their functions with the required safety margins.

LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup 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, Primary Containment Functional Design concludes that the CS system 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 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. 1–Issuance of Amendment Regarding Alternative Source Term, November 26, 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
- the system which maintains condenser vacuum once it has been established.

FPL’s review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists).

The NRC’s acceptance criteria for the MCES are based on:

- 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 SRP Section 10.4.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The St. Lucie Unit 1 specific GDCs for the main condenser evacuation system are as follows:

- 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.

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.

Radioactive waste management and monitoring is discussed in UFSAR Chapter 11. Area monitoring is discussed in UFSAR Section 12.1.4.

As described in UFSAR Section 10.4.2, the MCES, consists of two hogging ejectors, two steam jet air ejectors with associated inter- and after-condensers, manifolds, valves and piping. The system is designed to establish and maintain condenser vacuum during start-up and normal operation.

During start-up, the two hogging ejectors evacuate a combined turbine and main condenser (empty hotwell) steam space of 142,000 cubic feet within a period of 60 minutes and thereafter maintain a condenser pressure of 5 in. Hg absolute. The steam jet air ejectors are designed to remove non-condensable gases and water vapor to provide condensate dearation and to maintain a condenser vacuum of 3.5 to 1 in. Hg absolute during start-up and normal operation.

Non-condensable gases from the steam jet air ejectors are monitored for radioactivity prior to being discharged to the plant vent. The presence of radioactivity would indicate a reactor coolant-to-secondary system leak in the steam generators. The condenser air ejector gas monitor measures non-condensable fission product gases in the condenser air ejector discharge to detect any primary to secondary leakage. Activity levels are recorded in the control room and alarms annunciated when the activity level exceeds predetermined limits.

In addition to the licensing basis described in the UFSAR, the MCES was evaluated for St. Lucie Unit 1 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 from 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 while the auxiliary priming ejectors, along with associated vacuum tanks, maintain the water seal in the condenser water boxes by removing air released from the circulating water.

The MCES has a sufficient capacity to facilitate plant startup and maintain condenser vacuum at all plant operating loads by removing all non-condensable gases and air-inleakage to the condenser.

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 deaerate the condensate and maintain condenser 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 and condensate dearation is maintained by the two-stage, twin element, steam jet air ejector. The steam jet air ejectors have a rated capacity of 50 cfm (25 cfm each element). The steam jet air ejectors pass the non-condensable gases to the plant vent, after being screened for radioactivity by a radiation monitor.

The main function of this condenser 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 1 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 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 Exchange 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 waterboxes. 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.

Since there is no potential for explosive gas mixtures in the condenser, it was not included in the evaluation.

2.5.3.2.2.3 Evaluation of 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 any are 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 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 3,363,156 lb/hr and the EPU steam flow rate to each condenser shell is 3,755,995 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 waterboxes upon startup is not changing.

The total air release rate will increase from a current rate of approximately 467 lb/hr (117 lb/hr per ejector) to a rate of approximately 509 lb/hr (127 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. Therefore, the existing auxiliary priming ejectors are adequate for EPU, without modifications.

The design of the MCES does not change following 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 from St. Lucie Unit 1 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 to 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 Systems

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 & 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 SRP Section 10.4.3.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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.

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.

The condenser air removal system discharge is monitored for gaseous activity. Radioactive waste management and monitoring is discussed in UFSAR Chapter 11. Area monitoring is discussed in UFSAR Section 12.1.4.

The turbine gland sealing system is described in UFSAR Section 10.4.3.

The turbine gland steam system controls the steam pressure to the turbine glands 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. The design of the diaphragm operated valves is “fail safe” such that failure of any valve will not endanger the turbine.

Gland steam is supplied from the main steam header. Each of the low pressure (LP) turbine glands has a gland steam supply regulator. Both high pressure (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.

Condensate from the hotwells is pumped through the steam jet air ejector condensers and the gland steam condensers for condensing the supply of steam from the steam jet air ejectors and gland sealing steam.

In addition to the licensing basis described in the UFSAR, the turbine gland sealing steam system was evaluated for St. Lucie Unit 1 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 have 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 effects 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
- 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 steam leakage from the HP turbine into the gland sealing system will increase which is used to supply sealing steam for the LP turbine. Therefore, 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 is individually controlled and is maintained at 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 turbine 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 1 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 1 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 to meet its current licensing basis with respect to maintaining its ability to control releases of radioactive materials to the environment and 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 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 1, is to cool the spent fuel assemblies and keep the fuel covered with water during all storage conditions. Florida Power & Light's (FPL) review focused on the effects of the extended power uprate (EPU) on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. Refer to LR Section 2.7.4, Spent Fuel Pool Area Ventilation System, for additional details.

The NRC's acceptance criteria for the spent fuel pool cooling and cleanup system are based on 10 CFR 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 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, including loss of offsite power;
- 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 measures to prevent a significant loss of fuel storage coolant inventory under accident conditions.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.1.3, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of Review Standard (RS)-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the licensing history with respect to the GDC.

The St. Lucie Unit 1 design bases are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the

St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1. The specific GDC applicable to the fuel pool system are:

- GDC-5, 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 1 fuel pool system does not share safety-related SSCs with St. Lucie Unit 2.

- GDC-44, 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, UFSAR Sections 3.1.44 and 9.1.3 state that 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 fuel pool system, component cooling water (CCW) system and the intake cooling water (ICW) system.

The cooling portion of the fuel pool system is a closed loop system consisting of two full capacity pumps and one full capacity heat exchanger. This system is designed to remove the decay heat generated by up to 1849 irradiated fuel assemblies stored in the fuel pool, while maintaining pool water temperatures < 150°F. The CCW system is a redundant closed loop system which removes heat from the shutdown heat exchangers, the fuel pool system, containment cooling water system and other essential and nonessential components as described in UFSAR Section 9.2.2. The ICW system is a redundant 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 ICW pumps normally take water from the Atlantic Ocean through the circulating water intake conduits and canal.

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 their safety functions.

- GDC-61, 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 (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 under accident conditions, UFSAR Section 9.1.3.1 states that the fuel pool system is designed to remove decay heat from up to 1849 spent fuel assemblies stored in the pool and maintain pool water temperature less than 150°F. Per UFSAR Section 9.1.3.4.3.2, there are several sources of fresh water on the site that are available to the fuel handling building; namely, refueling water storage tank, city water storage tanks via the fire main, city water storage tanks via the portable fire pump connection, and the primary water tank. The concurrent loss of these sources and the fuel pool cooling system is remote. Due to the fuel pool's inventory boil-off rate, there is sufficient time to obtain 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 connection via the hose connections can provide 150 gpm of 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 9.1-14, after an instantaneous full core offload 120 hours after shutdown, the spent fuel pool bulk temperature reached a maximum of approximately 125°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 reached a maximum of approximately 161°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 spent fuel pool.

In addition to the licensing basis described in the UFSAR, the fuel pool system was evaluated for St. Lucie Unit 1 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 the 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 the fuel pool heat exchanger are in operation, as well as situations where only a single fuel pool cooling pump is in service have been considered. These scenarios are discussed, along with their respective results, in Section 9.1.3 of the UFSAR. 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.

The UFSAR documents an assessment of local temperature conditions in the vicinity of a hypothetical fuel rod having the upper bound surface heat flux. 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 closed loop system having two full capacity cooling pumps and one full capacity heat exchanger. 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 discharge header pressure condition, an open pump breaker, a pool high temperature, or 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 is delayed 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., Metamic^{TM}) insert, added to each Region 1 and Region 2 rack storage cell, is considered. Because of analysis differences and because core offload 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 96 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 the 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 fuel pool cooling pumps are assumed to be in operation. The offload is initiated at 140 hours after reactor shutdown. The maximum CCW temperature to the fuel pool heat exchanger 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 pump

  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 fuel pool cooling pump on the fuel temperature rise at the time of maximum heat load, which is at the end of offload. The temperature increase will be used to set the limit on the maximum pool temperature, such that a single failure (loss of one fuel pool cooling pump) 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 defueling rates in excess of those 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 average defueling rates of 4 to 7 assemblies per hour, based on the variation in CCW temperature from 100°F to 95°F, when offload is initiated at ≥ 140 hours after shutdown.

- Scenario 3 - Full Core Offload, considering the failure of a fuel pool cooling pump

  The maximum thermal overshoot of 12°F has been determined to result from a full core fuel offload initiated at140 hours after reactor shutdown. The procedural upper limit for the spent fuel pool temperature during full core offload will be set so as to ensure that 150°F limit is not exceeded in the event of a failure of one fuel pool cooling pump, after accounting for the maximum thermal overshoot.

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.

As for the 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 high values for the water volume displaced by rack bearing pads, fuel assembly hardware, and Metamic^{TM} inserts. These assumptions, and others, lessen the 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. After the onset of boiling, makeup requirements remain well below the 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.

Each rack type in the fuel pool was analyzed to determine the limiting (i.e., highest) hydraulic resistance. Region 1 and 2 rack cells were assumed to contain Metamic^{TM} inserts. A value bounding this calculated resistance was applied to all storage cells in the fuel pool, including the location containing the hottest fuel assembly, in order to quantify the peak local water temperature. A decay heat analysis calculated a bounding peak fuel cladding temperature for the hottest fuel assembly and compared it to the local saturation temperature.

As noted, local temperature analyses calculate a bounding peak local water temperature in the storage rack cell containing the hottest fuel assembly, after applying a hydraulic resistance value suitable to bound conditions present in the fuel pool and cask pit rack. The local 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 submerged partial-height wall, such that the top portion of the cask pit is open to, and hydraulically coupled with the spent fuel pool. Because of this hydraulic coupling, the local temperature analysis neglects the partial height wall and assumes a free exchange of water between the two regions. Thus, decay heat generated by spent fuel assemblies stored in the racks is treated as a volumetric heat source in a porous media region. Given the model's treatment of inlet cooling flow to the fuel pool, neglect of the partial-height wall reduces available downcomer flow area, and is conservative.

Modeling of these features and phenomena considers that decay heat generated by stored fuel is transferred to the water, inducing a buoyancy-driven upward flow through each 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.

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 for local boiling in the racks is conservatively defined at the top of the active fuel when seated in the racks: a depth of approximately 26 feet. At this depth, the saturation temperature of water is approximately 242°F.

As can be seen from the post-EPU results, the calculated peak local water temperature is 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., 96 highly-burned assemblies)
- 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 Section 9.1.3.4 of the UFSAR 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 U235 enrichment and a discharge burnup of 55,000 MWD/MTU is unlikely to be present in the St. Lucie Unit 1 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 and Technical Specification (TS) requirements.
- 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 assumed to be at its minimum value from a procedurally-acceptable range of values.
  - Fouling of the heat exchanger surfaces and levels of tube plugging are assumed to exceed St. Lucie Unit 1'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.
  - When two fuel pool system pumps are assumed to be operating, only 50% of the flow from the second pump is credited. 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 analyses, which maximizes local temperatures.

• Maximizing Local Temperature Conditions

- The plenum gap 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.
- Downcomer flow between the rack modules is assumed not to occur (the actual rack-to rack spacing gaps are neglected). Rack to wall gaps where downcomer flow does occur are modeled at less than their actual spacing. 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. Both items contribute to maximizing the local temperature.
- The resistance effects of Metamic^{TM} 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 chevron-shaped Metamic^{TM} insert blocks one-half the side holes near the bottom of the rack cell and the insert's head piece blocks 2/3 of the cell flow area at the top of the insert above the fuel assembly.

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 (Metamic^{TM} inserts) to the rack storage cells. Refer to LR Section 2.8.6.2, Spent Fuel Storage, for information on management of Metamic^{TM} 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.

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 concurrent single active failure. A limiting value of thermal overshoot, applicable to full core fuel offload evolutions has been determined. Operational guidance developed to control performance of fuel offload evolutions during EPU conditions, will incorporate these results.

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 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 1 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. The implementation of EPU does not affect the capability of the system to perform this function.

The evaluation of the fuel pool system at EPU conditions demonstrates that St. Lucie Unit 1 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 GDCs -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[a]

Offload Scenario	Minimum Time-to-Boil (hrs)	Maximum Boil-off Rate (gpm)
Scenario 1	9.8	42.3
Scenario 2	4.5	75.0
Scenario 3	4.5	75.0

a. The values provided are based on a bounding fuel offload rate of 7 assemblies per hour, beginning at 140 hours after reactor shutdown.

Table 2.5.4.1-2
Peak Local Temperatures in Fuel Pool

Parameter	Value (°F)
Local Water Temperature	184
Cladding Superheat	43
Local Fuel Cladding Temperature	227

2.5.4.2 Station Service Water System

2.5.4.2.1 Regulatory Evaluation

The station service water system, referred to as intake cooling water (ICW) system, provides essential cooling to safety-related equipment and also provides cooling to non-safety-related auxiliary components that are used for normal plant operation. FPL's review covered the characteristics of the ICW components with respect to their functional performance, as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a 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;
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided.

Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13 and GL 96-06.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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.

- 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 (UHS) (a safety-related structure) 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 electrical 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 ICW system.

The ICW system is an open loop system which removes heat from the CCW system and transfers it to the UHS, 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 (TCW) and open blowdown cooling system (OBCW) heat exchangers, which are isolated automatically upon receiving safety injection actuation signal (SIAS). Only one essential header is needed to remove the heat generated under post-LOCA conditions.

The ICW 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 which serves as the UHS. The UHS is discussed in UFSAR Section 9.2.7.

In addition to the licensing basis described in the UFSAR, the ICW system was evaluated for St. Lucie Unit 1 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
- 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 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, Instrumentation and Controls

- 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
  - 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 Evaluation of 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 any are 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 1 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; Section 2.5.1.1, Flooding; and Section 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 1 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 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 condition.

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 system and the ICW system 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 1 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)
- OBCW heat exchangers (non-safety-related)
- Lubricating water to the circulating water pumps (non-safety-related).

The TCW and OBCW heat exchangers 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 system design temperature of 125°F.

The accident analyses allowed for 10% CCW heat exchanger tube plugging.

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. 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 exchanger 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, including blowdown flowrates, 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 484,000 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% 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 at St. Lucie Unit 1 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 GL 96-06 are not applicable to St. Lucie Unit 1.

2.5.4.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the ICW system 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 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 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 system.

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)	139.90	152.37	118.30	95	118.19
LOCA Containment Pressure/Temperature Analysis(2)	130.66	142.02	110.27	95	116.66
CCW System Design Supply Temperatures			120.00		
ICW System Design Outlet Temperature					125.00

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.

Table 2.5.4.2-2
EPU Normal Conditions

	Pre-EPU Heat Load (MBTU/hr)	EPU Heat Load (MBTU/hr)
TCW heat exchangers	52.4	74.1
CCW heat exchangers	51.3	53.2
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 & Light (FPL) utilizes the nomenclature component cooling water (CCW) system for St. Lucie Unit 1 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, and (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 reactor auxiliary cooling water system 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 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;
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided.

Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13, 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to each GDC is 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 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 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 Class I seismic pipe which causes a 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.

  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 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 electrical 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 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 will not prevent the system from performing its safety function.

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 (designated N), which is connected to both essential headers during normal operation, is automatically isolated from both by valve closure on a safety injection actuation signal (SIAS). During normal operation, the nonessential header supplies cooling water to the following components: fuel pool heat exchanger, sample heat exchangers, waste gas compressors, letdown heat exchanger, control element drive mechanism (CEDM) air coolers, reactor coolant pump (RCP) motors, RCP seals, containment air compressors, steam generator blowdown sampling panel, and condensate recovery system sample cooler.

The A and B headers serve the following components:

Header A	Header B
Shutdown heat exchanger 1A	Shutdown heat exchanger 1B
Containment fan cooler 1A	Containment fan cooler 1C
Containment fan cooler 1B	Containment fan cooler 1D
Low pressure safety injection pump 1A	Low pressure safety injection pump 1B
High pressure safety injection pump1A	High pressure safety injection pump 1B
Containment spray pump 1A	Containment spray pump 1B

FPL's response to NRC Generic Letter (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.

FPL's response to NRC GL 89-13, 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, Classification of Structure, Systems, and Components and associated Table 3.2-1, Design Classification of Structure, Systems, and Components, which classify 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 5.2.4, Reactor Coolant Pressure Boundary Leakage Detection Systems, which describes the design features for detecting leakage of radioactivity into the CCW system.
- UFSAR Section 6.2.1.1, Containment Functional Design, which describes the engineered safety features used to mitigate the consequences of a LOCA.
- UFSAR Section 6.2.2, Containment Heat Removal Systems, which describes the design of the containment fan coolers, and associated Table 6.2-10, Single Failure Analysis – Containment Heat Removal System, which analyzes the CCW system for credible single active failures.
- UFSAR Section 6.2.4, Containment Isolation System and associated Table 6.2-16, Containment Penetration and Isolation Valve Information, which describe 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 St. Lucie Unit 1 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 (designated N), which is connected to both essential headers during normal operation, is automatically isolated from both by valve closure on a SIAS. 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 NRC GL 89-13)
- CCW system temperature limits
- Design pressure/temperature of piping and components versus the EPU operating pressures and temperatures
- CCW relief valve capacities
- 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 2.2.2.2, 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, Instrumentation and Controls
- 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 LR 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
- 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 2.8.4.4, Residual Heat Removal System
  - 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
  - LR Section 2.7, Habitability, Filtration, and Ventilation
- Post-accident heat removal requirements – LR Section 2.6.1, Primary Containment Functional Design
- 10 CFR 50 Appendix R cooldown – LR Section 2.8.4.4, Residual Heat Removal System.

2.5.4.3.2.3 Evaluation of 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 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.

2.5.4.3.2.4 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 1 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 of Electrical Equipment. As described in LR Section 2.5.1.3, Pipe Failures, the flooding analysis has considered the effects of high energy failures and evaluated the worst case failure in each plant building/area. The CCW system is a moderate energy system. Flooding from moderate energy systems was addressed in the design by consideration of the fire main pipe rupture as described in LR Section 2.5.1.1, Flooding. Previous piping failure analysis with respect to the CCW system are not affected by EPU conditions, since the CCW system flow rate and pressure do not change at EPU and no physical changes are being made to the system.

The evaluation of the CCW system capabilities at EPU conditions demonstrates that St. Lucie Unit 1 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 physical changes are being made to the CCW system and no new operating modes or system lineups are required as a result of the EPU. Therefore, the CCW system continues 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 1 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
- Low pressure safety injection pumps

- 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
- Spent fuel pool heat exchanger
- Containment instrument air compressors
- Condensate recovery system sample cooler

These cooled components are capable of removing the required EPU heat loads with the existing CCW supply flow rates. 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.

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
- 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 (+0.09 MBtu/hr) and the spent fuel pool heat exchanger (+1.8 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 SDC 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 containment fan coolers (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 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 containment analysis were conservatively modeled to maximize containment temperature and pressure. The containment response analysis discussed in LR Section 2.6.1 conservatively assumed emergency diesel generator (EDG) under-frequency, which resulted in lower CCW flow rates and lower credited heat removal rates by the CFCs. The results indicate CCW heat removal rates at EPU conditions that are lower than the analysis of record. During the injection phase, this is due to conservative CFC heat removal values. The lower credited heat removal during the recirculation phase is 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 confirm that the CCW heat exchangers provide sufficient heat removal for mitigation of postulated accidents. An additional LOCA analysis was performed which assumed EDG over-frequency, which conservatively maximized the CCW temperatures and heat loads at EPU. The results of this analysis show increased heat loads for both the injection and recirculation phases. However, the 120°F CCW 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 rate does not change at the EPU conditions and no physical changes are being made to the system. There is no change to the CCW pump head performance at EPU conditions. 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. Therefore, the EPU operating conditions will continue to be bound by existing analyses. 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 in temperatures that are bounded by the relief valve design. Since the EPU condition is 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 reactor coolant pump 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 loss-of-coolant accidents (LOCA) and main steam line breaks (MSLB) 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 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, Primary Containment Functional Design 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% 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 FPL has adequately accounted for the increased heat loads from the proposed EPU on system performance. 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.

FPL's review focused on the impact that the extended power uprate (EPU) has on the decay heat removal capability of the UHS. The 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 St. Lucie Unit 1 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 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.2.5.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 (a safety-related structure) 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 LOCA on one unit while safely shutting down the other unit.

- GDC-44 is described in 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.

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.

UHS consists of two independent water sources and their associated canals and conduit. The primary water source draws water from the Atlantic Ocean via the circulating water system intake as described in UFSAR Section 9.2.7.2. The secondary source of cooling water is Big Mud Creek, which is connected to the Atlantic Ocean through the Indian River (see UFSAR Figure 1.2-1). UHS is shared by St. Lucie Units 1 and 2.

UHS concept for the plant complies with the regulatory positions of Atomic Energy Commission (AEC) Regulatory Guide 1.27. Regulatory positions are specified in UFSAR Section 9.2.7.3

UHS has sufficient cooling water capacity to dissipate reactor decay heat during normal and emergency shutdown conditions. UHS is designed to provide sufficient cooling water for more than 30 days to achieve and maintain safe shutdown in both units or to permit control of a loss-of-coolant accident (LOCA) in one unit and concurrent safe shutdown of the second unit.

UFSAR Section 9.2.7.3.1 details the availability of the primary or secondary source of water during design conditions.

The circulating water system is designed 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 UHS.

Under seismic conditions, there are several credible failure modes for the intake canal. The canal could liquefy reducing but not blocking its cross-sectional area. Because only 6 percent of the initial cross-sectional area is required to supply cooling water, there will be no loss of function. A slope stability analysis assuming soil liquefaction in the emergency canal and intake canal is presented in UFSAR Section 2.5.5. The analysis demonstrates that the channel remains open to the intake structure with a minimum of 7 times the required cross-sectional area for 130 cfs flow (two unit requirement) at 1 fps average velocity.

Liquefaction analysis was performed based on a 1/20 slope as shown in UFSAR Section 2.5.5 (which overpredicts the worst slopes measured (1/8 to 1/10) for liquefaction following a severe earthquake). At the headwall, liquefied soil could partly fill-in the canal and block the pipes if the units are in a shutdown condition; however, analysis demonstrates that if one or both units are operating, the 5 fps (one unit) or 10 fps (2 units) water velocity exiting the intake pipes will scour sands clear of the pipes and headwall structure. In this matter, the headwall structure will prevent sands from the dikes slopes from closing off the intake lines. Refer to UFSAR Figure 9.2-6b.

In addition to the licensing basis described in the UFSAR, the UHS was evaluated for St. Lucie Unit 1 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 3.3.5 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 9.2.7.3 in the 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. These effects were evaluated against the State of Florida Industrial Wastewater Facility Permit No. FL0002208 limits for the St. Lucie LR Section 2.5.8.1, Circulating Water System.

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.
- 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 Evaluation of 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. No changes are required to be made to the UHS Technical Specification 3/4.7.5 due to EPU.

General Design Criteria

The evaluation of the UHS capabilities at EPU conditions demonstrates that the St. Lucie Unit 1 will continue to meet its 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 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 St. Lucie 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 which results in higher discharge flow temperatures as discussed in LR Section 2.5.8.1, Circulating Water System. ICW discharges into the circulating water outlet piping prior to its discharge to Atlantic Ocean. 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 484,000 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 circulating water system will operate within the limits of 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 meet its current licensing basis with respect to 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

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).

FPL's review for the EPU focused on the system's ability to provide sufficient emergency feedwater flow at the expected conditions (e.g., steam generator pressure) to ensure adequate cooling with the increased decay heat. FPL's review also considered the effects of the EPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions.

The NRC's acceptance criteria for the AFW system 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;
- 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;
- 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 SRP Section 10.4.9.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to the GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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.

The AFW system is designed to withstand pipe rupture effects, including pipe whip and jet impingement forces, and to perform its design function following design basis natural phenomena (i.e., following a hurricane, tornado, or a safe shutdown earthquake). The AFW system is designed to provide sufficient capability to maintain the reactor coolant system (RCS) in hot standby conditions following a high energy line break in the AFW system concurrent with a single active failure. (The AFW system was not categorized as a high energy system as part of original licensing. This basis is in accordance with the acceptance criteria invoked by SRP 10.4.9, Rev. 1 and Branch Technical Position ASB 10-1, Rev. 1).

- 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 CST 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.

The 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. 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.

- 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 whole 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.

Following proven power plant design philosophy, all 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 abnormal conditions. Shielding is designed to maintain tolerable radiation exposure levels (maximum of 3 rem integrated whole body dose over a 90-day period) following design basis accidents (refer to UFSAR Section 12.1). The control room will be isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system is designed to recirculate control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 12.2. 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 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.

Residual heat removal capability is provided by the shutdown cooling system (SDCS) (UFSAR Section 9.3-5) for reactor coolant temperatures less than 325°F. For temperatures greater than 325°F, this function is provided by the steam generators (SGs) and the AFW system. Sufficient redundancy, interconnections, leak detection, and isolation capabilities exist in each of these systems to assure that the residual heat removal function can be accomplished, assuming a single failure. Within appropriate design limits, either system can remove fission product decay heat at a rate such that specified acceptable fuel design limits (SAFDL) and the design conditions of the reactor coolant pressure boundary are not exceeded.

If the unit is operating at power and there is a turbine trip, there will be a “fast-dead bus” automatic transfer of power to the startup transformers. If offsite power is lost, the electrical equipment required for safe shutdown is loaded on the emergency diesel generators. Refer to UFSAR Sections 7.4 and 8.3.2.

- 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.

Although the AFW system is not specifically addressed by this GDC, the AFW system does provide for heat removal from the reactor and transfer 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 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 10.5 documents details of the AFW system design. Additional details that define the licensing basis for the AFW system are described in:

- UFSAR Section 9.2.8 describes how the CST is a source for feedwater for the AFW system.
- UFSAR Section 15 describes how the AFW system is credited in the mitigation of transients and accident conditions.

TS 3/4.7.1.2, Auxiliary Feedwater System, ensures operability of all AFW pumps.

TS 3/4.7.1.3, Condensate Storage Tank, ensures operability of the CST and that it contains minimum required volume of demineralized water.

In addition to the licensing basis described in the UFSAR, the AFW system was evaluated for St. Lucie Unit 1 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 for the reactor core. The heat removal allows the operator 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 service to support 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 signal (AFAS)
- Water supplies and sources (CST)
- 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 Analyses
- Operation of the AFW system during SBO and Appendix R fire scenarios - LR Section 2.3.5, Station Blackout and LR Section 2.5.1.4, 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 Systems
- Environmental qualification of pumps and valves - 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 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
- Operation following a small break LOCA - LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents

2.5.4.5.2.3 Evaluation of 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 1 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 60% to 70% 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 1 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 1 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, which 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, Occupational and Public Radiation Doses, LR Section 2.7.1, Control Room Habitability System and LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

The evaluation of the AFW system capabilities at EPU conditions demonstrates that St. Lucie Unit 1 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 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

The check valves downstream of AFW motor operated discharge valves function as containment isolation valves for the AFW system. The valves will be automatically closed in the event of non-flow system conditions and are capable of supporting the containment isolation function after EPU implementation.

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)

TS 3/4.7.1.3, Condensate Storage Tank, is being amended as part of the EPU license amendment request to address the higher decay heat removal requirements. The amended TS will change from a “minimum contained volume of 116,000 gallons” to a “minimum contained volume of 153,400 gallons." At EPU conditions, the usable water volume of 130,500 gallons is required in the CST to accommodate the decay heat removal for 7.66 hour cooldown period including the RCS at hot standby condition for 1 hour in order to reduce the reactor coolant temperature to shutdown cooling entry condition (325°F) in the event of loss of offsite power. The total required CST water volume in order to maintain the required usable water volume of 130,500 gallons is 153,400 gallons, including 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. The CST contains sufficient usable volume to support AFW operation following the implementation of the EPU in accordance with the amended requirements of TS Section 3/4.7.1.3.

The key CST volume parameters at pre-EPU and EPU are shown in the 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 Unit 1 AFW pump suction lines and the Unit 2 CST to be used under administrative control. Check valves prevent inadvertent draining of the Unit 2 CST to the 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 EPU CST volume requirement.

Since there are no physical modifications to the AFW system required to implement the EPU, this system continues to conform 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 S-RELAP5 code using nominal plant conditions. A limiting single failure concurrent with a limiting AFW line break was assumed. For this analysis, the initiating event is a loss of main feedwater. The limiting single failure is one of two motor-driven AFW pumps. The limiting AFW line break may occur in one of two possible locations, resulting in the following scenarios:

- Single Motor-Driven AFW Pump – One potential break location is at the discharge of the turbine-driven AFW pump. In this case, only a single motor-driven AFW pump is available to furnish feedwater to one SG.
- No Motor-Driven AFW Pumps – The second potential AFW line break location is the discharge of the second motor-driven AFW pump. In this case, the operators must initiate flow from the turbine-driven AFW pump before the RCS loses subcooling and the pressurizer becomes liquid solid.

Acceptance criteria used in the analyses for these break locations are as follows:

- Pressures in the RCS and main steam system should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.
- 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 pressure acceptance criterion requires that the pressures in the reactor coolant and steam systems must be maintained below 110% of their respective system design pressures. The challenges to peak primary and secondary overpressure are less for this event (with reactor scram and nearly coincident secondary-system isolation) than for the loss of external load event (with early termination of secondary-system steam flow in conjunction with continued operation at power until reactor trip). Thus, the primary system pressure limit is satisfied for this event as long as the pressurizer does not become liquid-filled and the pressurizer retains a steam "bubble" for pressure control. In addition, the peak secondary system pressure is bounded by the peak secondary system pressure in the loss of external load event. Thus, the secondary system overpressure limit is satisfied for this event since the limit was demonstrated to be satisfied in the loss of external load event.

The departure from nucleate boiling (DNB) acceptance criterion requires that the minimum departure from nucleate boiling ratio (MDNBR) is not less than the 95/95 correlation limit. The DNB SAFDL is not challenged during the short-term-heatup phase of the event because the reactor coolant conditions at reactor scram are close to the initial steady-state values. The DNB SAFDL is not challenged during the long-term heatup phase of the event provided that RCS subcooling is sufficient for decay heat removal. Thus, the DNB SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

The fuel-melt acceptance criterion requires that none of the fuel rods in the core experience fuel centerline melt. The fuel-melt SAFDL is not challenged during the short-term-heatup phases of this event because the reactor power level and peaking at scram are close to the initial steady-state values. The fuel-melt SAFDL is not challenged during the long-term-heatup phase of the loss of normal feedwater flow events provided that RCS subcooling is sufficient for decay heat removal. Thus, the fuel-melt SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

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 power operated relief valves (PORVs) and/or pressurizer safety valves. Thus, the plant condition restriction is satisfied for this event if the pressurizer level remains below the PORV inlet piping penetrations.

The results of the analyses relative to the use of a single motor-driven AFW pump, demonstrate that the degraded 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. The primary temperature is controlled by the actuation of the steam dump and bypass system. Thus, all acceptance criteria are satisfied for this event.

The results of the analyses relative to the use of no motor-driven AFW pumps indicates that with no automatic initiation of AFW flow, there is ample time (more than 10 minutes after event initiation) for the operators to start the turbine-driven AFW pump prior to losing subcooling margin and filling the pressurizer.

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 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	116,000	130,500
Unusable volume due to outlet nozzle location, vortex suppression, and instrument uncertainty	---	22,900
Technical Specification minimum total volume	116,000	153,400
Low level alarm volume above CST outlet nozzle	185,000	185,000

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. FPL's review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads).

The NRC's acceptance criteria for the MSSS are based on:

- 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-34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core.

Specific review criteria are contained in SRP Section 10.3.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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. Local missile barriers are 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.

Seismic Class I piping is arranged or restrained such that in the event of rupture of a Class I seismic pipe which causes a 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.

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, 3.7.5, 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 Units 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.

Residual heat removal capability is provided by the shutdown cooling system (UFSAR Section 9.3-5) for reactor coolant temperatures less than 325°F. For temperatures greater than 325°F, this function is provided by the steam generators (SGs) and the auxiliary feedwater (AFW) system. Sufficient redundancy, interconnections, leak detection, and isolation capabilities exist in each of these systems to assure that the residual heat removal function can be accomplished, assuming a single failure. Within appropriate design limits, either system can remove fission product decay heat at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

UFSAR Section 10.3, documents details of the main steam system design. Additional details that define the licensing basis for the main steam system are described in:

- UFSAR Section .2.2.1 which describes the protection of the main steam system from overpressurization.
- UFSAR Section 6.2.4 which describes the containment isolation features to isolate the main steam system

Technical Specification (TS) 3/4.7.1.1, Safety Valves, ensures all main steam line code safety valves be operable with lift settings as specified in TS Table 4.7-1.

TS 3/4.7.1.5, Main Steam Line Isolation Valves, ensures the operability of main steam isolation valves (MSIVs).

In addition to the licensing basis described in the UFSAR, the main steam system was evaluated for St. Lucie Unit 1 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 turbine 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 system
- 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
- 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 and turbine missiles – LR Section 2.5.1.2.1, Internally Generated Missiles and LR Section 2.5.1.2.2, Turbine Generator, respectively
- 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
- 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
- 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 Evaluation of 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 inlet throttle pressure of 756 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 SG outlet to the MSIV increases to 187 fps from 164 fps and exceeds industry design guideline velocity of 167 fps by 20 fps.
- Piping from the MSIV to the MSSS common header increases from 166 fps to 190 fps and exceeds industry guideline velocity of 167 fps by 23 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 external load evaluation 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% (8 valves) and 1040 psia +1/-3% (8 valves). The MSSV setpoints will remain unchanged for EPU. The tolerances on the MSSVs in TS 3/4.7.1.1 will be changed for operational flexibility ±3% for the MSSVs with the lower setpoint and +2%/-3% for the MSSVs with the higher setpoint. This tolerance change has been factored into the plant's accident analyses (LR Section 2.8.5.0).

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 reseat at a pressure below the opening pressure. The ADV set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest set MSSV. Since neither of these pressures changes for the proposed range of NSSS design parameters, the ADV setpoint is unchanged.

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 both ADVs (626,646 lbm/hr at 900 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 each consist of an assembly of two swing-type check valves welded together to essentially form a single valve, which is designed to protect the main steam header against reverse flow from one SG to the other in the event of a steam line rupture. The upstream check valve is positioned opposite to the typical direction for a check valve and is maintained open by means of an air operated actuator, which closes the valve upon a given signal that indicates a loss of pressure in the downstream steam lines. The downstream valve operates as a typical check valve and is maintained open by the normal steam flow. This valve closes upon loss of steam flow as a result of a steam line break upstream of the valve assembly.

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. The current MSIV design pressures and temperatures are acceptable at EPU conditions since they are equal to the piping design pressure and design temperature.

Due to EPU conditions, the main steam flow rate from each SG will increase from the normal operation pre-EPU total flow rate of approximately 5,892,295 lbm/hr to a post-EPU total normal flow rate of approximately 6,657,560 lbm/hr. Due to this increase in main steam flow rate, the MSIVs required evaluation, which confirmed satisfactory EPU performance, including the ability to meet the safety-related isolation function to prevent uncontrolled blowdown of both SGs in the event of a steam line rupture accident. The MSIVs will be modified to improve structural integrity and fatigue life in the event of spurious closure at EPU conditions.

The MSIVs are designed to close within 6.0 seconds. Although EPU main steam conditions result in higher flow rates, the EPU closure time remains bounded by the time specified in the TS under no-flow and no-load conditions. The MSIV is designed to use the reversing flow to assist in closure and, therefore, the increased steam flow under EPU conditions will enhance the closing of the valve, thus ensuring that the Inservice Testing (IST) Program/TS requirements for closing time are met

The MSIVs were evaluated for upstream and downstream pipe rupture under EPU closure forces and were determined to be bounded by the original stress analysis and therefore acceptable at EPU.

The MSIVs were also evaluated for erosion, vibration, differential pressure, and flow turbulence and were determined to be acceptable at EPU conditions.

The evaluation results presented above confirm that the current MSIVs are acceptable at EPU.

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% power generation
- Moisture removal capability of the moisture separator and internal drain system is sufficient for EPU moisture loading
- 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 low pressure (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 reheat stop and intercept valves to provide overspeed protection is discussed in LR Section 2.5.1.2, Missile Protection.

Auxiliary Main Steam Supply Flow Rates

The main steam system supplies steam to the following auxiliary loads:

- Moisture separator reheaters
- AFW pump turbine
- Auxiliary steam system
- Priming ejector
- Turbine gland sealing steam 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 HP turbine and MSRs 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, 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 SSCs remain acceptable to protect safety-related SSCs from the effects of pipe whip and jet impingement loading for EPU. Missile protection criteria is discussed is 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 SSCs and therefore complies with GDC-5.

2.5.5.1.3 Conclusion

FPL has reviewed the assessment of 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 Parameters

	Current Operating Condition	EPU Operating Condition
Steam Generator Outlet to Main Steam Isolation Valves		
Flow rate, lbm/hr	5,892,295	6,657,560
Pressure, psia	858.5	856.0
Temperature, °F	526.5	526.1
Main Steam Isolation Valves to MSSS Common Header		
Flow rate, lbm/hr	5,892,295	6,657,560
Pressure, psia	835.2	825.8
Temperature, °F	523.3	521.9
Main Steam Common Header		
Flow rate, lbm/hr	5,892,295	6,657,560
Pressure, psia	833.3	823.6
Temperature, °F	522.9	521.6
MSSS Common Header to HP Turbine Throttle Valves		
Flow rate, lbm/hr	5,436,470	6,171,570
Pressure, psia	824.3	815.6
Temperature, °F	521.7	520.4
MSSS Common Header to MSRs		
Flow rate, lbm/hr	224,754	240,402
Pressure, psia	824.3	815.6
Temperature, °F	521.7	520.4
Cold Reheat Piping – High Pressure Turbine Exhaust to MSR Inlet		
Flow rate, lbm/hr	2,255,763	2,548,782
Pressure, psia	221.4	234.6
Temperature, °F	390.4	395.4
Hot Reheat Piping – MSR Outlet to Low Pressure Turbine Inlet		
Flow rate, lbm/hr	2,048,953	2,293,589
Pressure, psia	213.8	230.6
Temperature, °F	496.4	508.8
Main Steam Design Pressure/Temperature		
Pressure, psig	985	985

Table 2.5.5.1-1 (Continued)
System Operating Parameters

	Current Operating Condition	EPU Operating Condition
Temperature, °F	550	550
Main Steam Pressure Drop (psi) SG to HP Turbine		
Pressure, psi	74.4	100

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). FPL's review focused on the effects of the 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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.

UFSAR Section 10.4.1 describes the main condenser:

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 storage capacity of the hot well is sufficient for four minutes of operation at maximum throttle flow. The hotwell supply of condensate is backed up by the condensate storage tank from which condensate may be admitted into the condenser.

Refer to UFSAR Table 10.2-1 for a listing of expected condenser radioactivity inventory during normal operation at the current power level.

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 St. Lucie Unit 1 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 the 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 has been 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 9.2.3. 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 the 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 installation of replacement spool pieces for the condenser air removal piping.

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 steam dump system following a load rejection 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 initiating any of the automatic plant protection setpoints.
- 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 following load rejection 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
- 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 Evaluation of 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. 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 4.74 HgA, considering a 90°F circulating water inlet temperature, exceeds the current low vacuum alarm setpoint of 26.25" HgV (3.65" HgA). This setpoint will be increased for EPU operation. 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 approximately 2/3 the depth of the tube field 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 feedwater pump recirculation connections will be modified as a part of the feedwater pump replacement. The remaining condenser connections and spargers have been evaluated and will perform satisfactorily at EPU conditions.

The modifications to the main condenser for EPU do not impact the ability of St. Lucie Unit 1 regarding the control of radioactive material in accordance with St. Lucie Unit 1 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	6140×10^6 BTU/hr	6865×10^6 BTU/hr
Condenser Backpressure		
65°F	Not Available	2.43 in HgA
75°F	2.81 in HgA	3.16 in HgA
90°F	Not Available	4.74 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the SBCS are as follows:

- 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 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 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.

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 SAFDLs and the design conditions of the RCPB 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 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.

Residual heat removal capability is provided by the shutdown cooling system (UFSAR Section 9.3-5) for reactor coolant temperatures less than 325°F. For temperatures greater than 325°F, this function is provided by the SGs and the auxiliary feedwater system. Sufficient redundancy, interconnections, leak detection, and isolation capabilities exist in each of these systems to assure that the RHR function can be accomplished, assuming a single failure. Within appropriate design limits, either system can remove fission product decay heat at a rate such that SAFDLs and the design conditions of the reactor coolant pressure boundary are not exceeded.

The SBCS described in UFSAR Section 10.4.4 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 accommodate a load rejection of up to 29 percent of rated steam flow without opening the pressurizer or the SG safety valves or causing a reactor trip.

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.

The total capacity of the dump valves and turbine bypass valve is 24 percent and 5 percent of rated steam flow, respectively.

The SBCS has no safety functions since overpressure protection is provided by ASME Code safety valves. Consequently, design of the system to seismic Class I or limiting environmental conditions is not required.

In addition to the licensing basis described in the UFSAR, the SBCS was evaluated for St. Lucie Unit 1 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% of the rated steam flow at full-load steam pressure without a reactor/turbine trip.

St. Lucie Unit 1 is equipped with 4 steam dump valves and 1 turbine bypass valve, with a total flow capacity of 3,682,843 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.
- 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 affect 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, the SBCS is 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 the greater rated steam flow for EPU operation. The modification will ensure that the system continues to comply with the current licensing basis requirements with respect to both the protection against dynamic effects (GDC-4) and the ability to provide a means for shutting down the plant during normal operations to reduce the demands on systems important to safety (GDC-34).

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 valves, and the motor-operated feedwater pump isolation valves. FPL's review focused on the effects of the 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 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:

- 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for the condensate and feedwater 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 (LOCA). 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.

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 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.

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.

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, 3.7.5, 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.

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 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 electrical 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 system and the intake cooling water system.

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.

The condensate, feedwater and heater drain systems, are shown on UFSAR Figures 10.1-2a, 2b, 2c, 2d, 2e and 10.1-3. The condensate is collected in the condenser hotwell. The condensate is returned to the SGs by means of two condensate pumps and two SGs feedwater pumps. The feedwater passes through five stages of heat exchangers (i.e., high and low pressure heaters) arranged in two parallel trains where it is heated by steam extracted from various stages of the turbine. The drains from the first three stages of low pressure heaters are eventually cascaded back to the condenser hotwell, and the drains from the fourth stage low pressure heaters and fifth stage high pressure heaters are returned to the feedwater system by two heater drain pumps.

The CFS is not designed to seismic Class I standards except for the piping from the SGs to the first check valve outside containment, and seismic Class I feedwater pump isolation valves. Details of isolation provisions are contained in UFSAR Table 6.2-16. The AFW system described in UFSAR Section 10.5 is used to achieve safe plant shutdown by removal of reactor decay heat from the SGs in the event of loss of the normal feedwater system or loss of offsite power.

Each SG feedwater line is provided with a three-element controller which combines the SG steam flow signal, feedwater flow signal and SG water level. The output of each three-element controller actuates the 100 percent capacity feedwater regulating valve to affect the desired feedwater flow to each SG. In addition to the air operated feedwater regulating valve, there is a 15 percent nominal capacity bypass valve that is used for automatic SG level control during power ascension and at low power levels. A 100 percent capacity motor operated bypass valve can be used to facilitate online maintenance of the main feedwater regulating valves. Refer to UFSAR Section 7.7 for a complete description of steam and feedwater control.

The design provisions for the prevention of feedwater instability (i.e., water hammer) are discussed in UFSAR Section 10.5.3. 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 St. Lucie Unit 1 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 heater 4A/B, two strings of single high pressure heaters, main feedwater regulator valves, main feedwater isolation 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 one heater drain pump discharge level control valve; all of 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 first check valve outside containment, and seismic Class I feedwater pump isolation valves. Details of isolation provisions are contained in UFSAR Table 6.2-16. The only parts of the CFS classified as safety-related are the feedwater pump discharge isolation valves and the feedwater piping from the SGs up to and including the first check valve outside containment, which encompasses the MFIVs. This portion of the CFS is located in the steam trestle which is a seismic Class I structure designed to withstand tornado missiles.

The feedwater piping from the SGs through the MFIVs, up to and including the first check valve outside of containment is classified as safety related and seismic Class I. 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. The feedwater pump discharge isolation valves, located in the turbine building, are also classified as safety related and seismic Class I.

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.)

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.
- Serves as a cooling medium to condense the steam from the turbine gland steam condenser and the steam jet air ejector 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.

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 power uprate conditions. The evaluation considered the effects of the power uprate on the following system and component design aspects:

- Design pressure and temperature on piping, 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
  - 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.
- 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 power uprate 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 of Electrical Equipment, which addresses the qualification of the safety-related MFIVs and feedwater pump discharge isolation valves
- 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 Control Systems, which evaluates condensate and feedwater instrumentation
- LR Section 2.5.4.5, Auxiliary Feedwater 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
- LR Section 2.8.5.0, 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 Evaluation of 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 provide the results of the evaluations of 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 1 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 1 as it is a dual unit installation. However, the CFS are not shared between the units with the exception of the CPFD 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 CPFD. Therefore, St. Lucie Unit 1 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 the St. Lucie Unit 1 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 these functions 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 2.8.5.0, 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. 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 bound the EPU operating conditions with the exception of the design temperature of the main feedwater pump recirculation valves. However, the valve body materials were evaluated and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures.

Feedwater Heaters

Feedwater heaters 1A/B through 5A/B and external drain coolers 1A/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 measures 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.

Based on the vendor's evaluation, the feedwater heaters shell and tube side design pressures and temperatures bound the EPU operating 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 0.3 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 on 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 pass partition plates.

In summary, the design and construction of the existing 1A/B through 4A/B feedwater heaters and drain coolers 1A/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. The feedwater pump recirculation piping will be replaced with larger diameter piping prior to implementation of EPU to bring flow velocities within acceptable guidelines. Other individual pipes are evaluated as part of the flow accelerated corrosion program as described in LR Section 2.1.8, Flow-Accelerated Corrosion.

Potential vibration issues resulting from increased flow velocities at EPU are evaluated in LR Section 2.12, Power Ascension and Testing Plan. 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, 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. 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. The “B” train heater drain pump discharge level control valve is smaller than the “A” train valve and will require modification to increase the flow coefficient and ensure adequate flow control capability at the EPU power level.

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 the feedwater isolation valves, with the feedwater pump trip providing backup. As discussed in UFSAR Section 6.2.1.3.2, for the main steam line break containment analysis, in the case of the MFIV failure, the main feedwater pump trip was credited. In accordance with the Standard Review Plan, Section 6.2.1.4, non-safety grade control systems may be utilized as a backup to the primary isolation.

The MFIVs and main feedwater pump discharge isolation valves 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 MFIVs and the check valves 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 Conditions	EPU Operating Conditions
Condensate System		
Flow Rate, lb/hr	8,282,260 (16,673 gpm)*	9,260,810 (18,664 gpm)*
Condenser Pressure, inches Hg Abs @ Circ Water Temp., °F	2.81 @ 75.0°F	3.16 @ 75.0°F
Condensate Pump Discharge Pressure, psia	596	564
Condensate Supply Temperature, °F (FW Pump Suction)	376.5	381.3
Heater Drain System		
Heater Drain Pump Flow, lb/hr	3,568,790 (7795 gpm)*	4,120,690 (9047 gpm)*
Heater Drain Pump Discharge Pressure, psia	604	557
Feedwater System		
Flow Rate, lb/hr	11,851,050 (26,950 gpm)*	13,381,500 (30,557 gpm)*
Feedwater Pump Discharge Pressure, psia	1,172	1,044
Steam Generator Supply Temperature, °F	435.0	436.7
Design Pressure – Main Feedwater Pump Discharge to Main Feedwater Isolation valves, psig	1875	1875
Design Pressure – Main Feedwater Isolation Valves to Steam Generator Inlet, psig	1100	1100
Design Temperature – Main Feedwater Pump Discharge to Steam Generator Inlet, °F	500	500
* Flow values in gpm 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

FPL's review focused on the effects that the 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 GWMS 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-reasonably achievable" (ALARA) criterion.

Specific review criteria are contained in SRP Section 11.3.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 Section 9.5.1.

- 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.

The waste management system is described in UFSAR Sections 11.2, 11.3 and 11.5, 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 20 and 10 CFR 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 20 and 10 CFR 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 in the event of noncompliance with 10 CFR 20 (see UFSAR Section 11.4 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 or 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 GWMS 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 as low as is reasonably achievable.

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 ALARA criterion of 10 CFR 50, Appendix I.

Additional information on the GWMS is provided in UFSAR Section 11.3.

In addition to the licensing basis described in the UFSAR, the GMWS was evaluated for St. Lucie Unit 1 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 gaseous waste management system 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 Chapter 18 of the UFSAR.

2.5.6.1.2 Technical Evaluation

2.5.6.1.2.1 Introduction

The GWMS 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 GWMS design functions are:

- Collect gas from reactor coolant degassing operations, radioactive liquid waste processing, tank purging, and tank venting from 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;
- 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 GWMS 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 system 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 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.

2.5.6.1.2.4 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. Refer to LR Section 2.10, Health Physics 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 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 Specifications 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 Section 13.8.1.4, Explosive Gas Monitoring Instrumentation, 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 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 affect on these requirements.

2.5.6.1.3 Conclusion

FPL has reviewed the assessment related to the GWMS. FPL concludes that the assessment 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 GWMS 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 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 LWMS 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-reasonably-achievable (ALARA) criterion.

Specific review criteria are contained in the SRP, NUREG-0800, Section 11.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDCs is discussed in UFSAR Section 3.1.

As discussed in UFSAR Section 11.2, Liquid Waste Systems, 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 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 (TS) and the Offsite Dose Calculation Manual (OCDM). The TS and OCDM 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

  UFSAR Section 3.1.61 and the sections relevant to the LWMS require that the system be designed to assure adequate safety under normal and postulated accident conditions. The system 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.

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 Chapter 12, Section 12.1.1.1.
- Individual LWMS processing components which contain significant radioactivity are located in within 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.

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 is 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 ALARA. 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} μCi/cc excluding tritium and dissolved fission product gases.

b. Limit the annual average tritium discharge concentration to 5×10^{-6} μCi/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 basis described in the UFSAR, the LWMS was evaluated for St. Lucie Unit 1 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 Chapter 18 of the UFSAR.

2.5.6.2.2 Technical Evaluation

2.5.6.2.2.1 Introduction

The LWMS is discussed in UFSAR Liquid Waste Systems; Section 11.2, Liquid Waste System; Section 11.4, Process and Effluent Radiological Monitoring Systems; and the 10 CFR 50 Appendix I Supplement to the St. Lucie Unit 1 Environmental Report, dated June 1, 1976.

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 station 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 activity 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.
- Waste monitor tanks – the final stop for all plant liquid wastes prior to release to the environment through the discharge canal. Liquid in these tanks is sampled for chemical and radioactivity concentration and is pumped to the circulating water discharge canal when it meets established release criteria.

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 – receives low activity, aerated and potentially dirty discharges.
- Chemical drain tank – receives waste streams that are normally low in activity but high in impurities.
- Laundry drain tanks – receive drainage from contaminated sinks and showers, laundry filters and various drains and drain tanks.
- Waste condensate tanks – receiving and storage tanks for processed waste water from various LWMS, water systems and spent resin tanks.

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:

- Aerated waste storage tank – receives liquid wastes from LWMS and SGBD tanks and waste ion exchangers.
- Waste monitor tanks.

Depending on the quality of the aerated waste storage tank contents, these wastes are sent through various filters, waste condensate tanks and ion exchangers for removal of radioactivity and impurities. Once cleanup is complete and the liquids are ready to be released, they are directed to the waste monitor tanks for discharge. If more processing is required, the cycle is repeated until the liquids are adequately cleaned to meet the discharge criteria prior to release. The discharge is continuously monitored and recorded and if the radiation monitor setpoint is exceeded, the release is automatically stopped.

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. Therefore, the system components are sized according to this criterion. The only liquid release point from the LWMS is via the waste monitor tanks to the circulating water discharge. 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. All radioactive materials are sampled for chemical and radiological concentrations prior to release to ensure compliance with 10 CFR 20 and 10 CFR 50, Appendix I and to determine release rates. If the contents of the tank are found acceptable in terms of environmental discharge limits, the tank contents are discharged. A radiation monitor is provided in the discharge line to verify that the fluid discharge is below the applicable radioactivity limits. In the event that the discharged activity is unacceptable, the discharge monitor automatically terminates discharge operations. 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 and on the basis of 10 CFR 100 site boundary dose guidelines.

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 Evaluation of 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 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 OCDM. There is no increase in radioactive materials, except as described in LR 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 affect 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 and -61 and 10 CFR 50, Appendix I, 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

FPL's 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;
- 10 CFR 71, which states requirements for radioactive material packaging.

Specific review criteria are contained in SRP Section 11.4.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971), final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

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 11.5, 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-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 11.4 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 11.5, 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 is 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 1, 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 20, 10 CFR 71 and 49 CFR 170-178.

In addition to the licensing basis described in the UFSAR, the SWMS was evaluated for St. Lucie Unit 1 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 11.5 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
- 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 various liquid waste system ion exchangers,
- Spent resins from the chemical and volume control system ion exchangers (purification ion exchangers, 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. 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 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, Occupational and Public Radiation Doses. Therefore, the management of the SWMS is acceptable for EPU.

The evaluation of the SWMS at EPU conditions demonstrates that St. Lucie Unit 1 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 1 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 solid waste management system at EPU conditions demonstrates that St. Lucie Unit 1 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. The FPL 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 structures, 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 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 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 Class I seismic pipe which causes a 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 Sections 3.5, 3.6, 3.7.5, 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 4.16 kV 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 a 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 onsite and offsite, both units can be electrically connected, under administrative control, such that a diesel generator set from the non-blacked out 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 coolant, containment integrity, and other vital safety functions are maintained.

  Provisions shall be included to minimize the probability of losing electrical 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, there will be 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 generators (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 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.

A contract is maintained with a fuel oil supply and/or shipping company for normal supply of diesel fuel oil. This source would be used under storm conditions if available. In the event that the local firms were also affected by the storm other means and sources of fuel oil would be arranged for in accordance with plant procedures and the site emergency plan.

In the unlikely event there were no bridges open which would permit trucking of fuel to the plant, a barge would be chartered to transport fuel oil from the Canaveral Terminal or the Port of Miami to the St. Lucie site in approximately one (1) day. Any of these facilities has on hand adequate diesel oil for the supply of the EDGs as a matter of routine. Barges are equipped with on-board pumps and hoses to off-load the fuel at the plant site.

In addition to the licensing basis described in the UFSAR, the EDG engine fuel oil storage and transfer system was evaluated for St. Lucie Unit 1 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 System. The design of the EDG fuel oil and transfer system provides electrical and physical separation of components to assure that the system can withstand an active or passive single failure as well as 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.
- Associated instrumentation and controls.

The EDG fuel oil storage tank and day tank levels are currently being administratively controlled in order to meet the design requirements associated with the use of ultra low sulfur fuel oil. St. Lucie Unit 1 TS 3.8.1.1 requires that the fuel oil storage system contain a minimum of 16,450 gallons of fuel in each storage tank. FPL imposed administrative control requires that 18,650 gallons of fuel be maintained in order to compensate for the use of ultra low sulfur fuel oil.

Subsystem A serves EDG 1A and subsystem B serves EDG 1B. 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 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the emergency diesel engine 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 operating duration of certain components following a postulated LOOP or a LOOP concurrent with a LOCA will increase due to the increased decay heat level under EPU conditions. 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 rates of the EDGs allow the maximum usable volume of the fuel oil storage system to run one EDG for 7.42 days and both EDGs for 3.70 days at their required post-LOCA loads. The capacity of both fuel oil storage tanks are required to support the EDG run time. 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 is provided as part of this license amendment request to capture the additional volume of ultra low sulfur fuel oil necessary to support EPU. The proposed change increases the minimum fuel storage system requirement for each diesel generator set from 16,450 gallons to 19,000 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 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 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 EDGs 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 its 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 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;
- GDC-62, insofar as it requires that criticality be prevented.

Specific review criteria are contained in SRP Section 9.1.4 and guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the design relative to the GDC is discussed in UFSAR Section 3.1.

Specifically, the adequacy of the design of the LLHS relative to:

- GDC-61 which 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 which 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. The UFSAR states that:

> New fuel assemblies are stored in racks in parallel rows having center-to-center distances of 21 inches in both directions. New fuel is stored in air in the new fuel handling area. The high density spent fuel storage racks consist of 18 distinct modules of varying size in two regions. The cask pit rack is a Region 1 rack designed for storage of fresh or spent fuel assemblies having enrichments of up to 4.5 weight percent (w/o) U-235. Fuel assemblies are stored at a nominal 10.30-inch center-to-center spacing in the cask pit rack. Region 1 spent fuel pool storage racks are designed for storage of higher enriched irradiated fuel, with initial enrichments of up to 4.5 w/o U-235, such as might be temporarily discharged as part of a full core fuel offload. Region 1 is also designed to store fuel assemblies with enrichments up to 4.5 w/o U-235 that have not achieved sufficient burnup to be stored in Region 2. The center-to-center spacing in Region 1 is 10.12 inches. Region 2 storage cells were designed for fuel of various initial enrichments, including 4.5 w/o U-235 assemblies burned to at least 34.66 MWd/KgU. The center-to-center spacing in this region is 8.86 inches. The spacing is sufficient to maintain keff less than 1.0 for all the new and spent fuel assemblies when in unborated water.
>
> 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.
>
> New fuel assemblies are delivered to the site in containers approved by the U.S. Department of Transportation. New fuel assemblies are removed from the shipping containers and placed in the new fuel storage racks using the new fuel handling tool attached to the 5-ton fuel transfer hoist.
>
> 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 the cooling medium for removal of decay heat. Although boric acid is added to the water, soluble boron is not required for subcriticality of the fuel stored in the spent fuel pool. The major components of the system are the refueling machine, the fuel transfer equipment and the spent fuel handling machine.
>
> Fuel hoisting units on the refueling machine and spent fuel handling machine are in accordance with Specification for Electric Overhead Traveling Cranes, EDCI Specification No. 61.

With respect to criticality accidents, the analyses and evaluations are presented in LR Section 2.8.6.2, Spent Fuel Storage.

UFSAR sections that address design features of the fuel handling systems include:

- Section 9.1.1, New Fuel Storage and Handling
- Section 9.1.2, Spent Fuel Storage
- Section 9.1.4, Fuel Handling Systems

- Section 9.6, Cranes-Overhead Heavy Load Handling System

In addition to the licensing basis described in the UFSAR, the fuel handling equipment was evaluated for St. Lucie Unit 1 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 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.

The fuel handling system related to light load handling of new and spent fuel consists of the following components:

- Fuel movement:
  - Refueling machine
  - Spent fuel handling machine
  - Upending machine
  - Fuel transfer tube, valve, and carriage
  - New fuel crane
  - New fuel elevator
  - Refueling machine auxiliary hoist
- Tooling:
  - Control element assembly (CEA) handling tool
  - Fuel handling tool (short tool for dry handling)
  - Fuel handling tool (long tool for underwater handling)
  - Surveillance capsule retrieval tool
  - CEA coupling tool

The design bases for the fuel handling system include:

- Safely handle and store fuel assemblies and control element assemblies.
- Safely remove, replace and store reactor internals.
- By means of interlocks, travel limiting devices and other protective devices, minimize the probability of malfunction or operator initiated actions that could cause fuel damage, and potential fission product release or reduction of shielding water coverage.
- Conduct all spent fuel transfer and storage operations under water to limit radiation dose levels to less than 2.5 mrem/hr at the pool surface.
- Operate in water with the chemistry listed in UFSAR Table 9.1-2.
- Maintain handled fuel in a safe condition in the event of loss of power.
- Withstand containment internal design leak rate test pressure without loss of function (non-removable equipment only).
- Remove and install a fuel assembly at each operating location at the most adverse combined tolerance condition for the equipment, core internals and fuel assemblies.
- Withstand the loadings induced by the design base earthquake.

These design bases ensure the movement and storage of new or spent fuel assemblies will be accomplished in a safe manner, preventing or minimizing the risk of fuel assembly damage and maintaining minimum radiation exposure in the vicinity of spent fuel storage and handling operations.

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 acceptance criteria discussed in LR Section 2.5.7.2.1. The evaluation will determine 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 Evaluation of 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 associated with LLHS related to refueling are not modified for EPU purposes, and St. Lucie Unit 1 will continue to use Areva-NP design 14x14 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. Existing provisions such as the hoist assembly spreading device and the mast anti-collision device on the refueling machine, and electrical and mechanical interlocks on the refueling and spent fuel machines, will prevent damage to new and spent fuel assemblies and the resultant release of radioactivity to the refueling cavity or spent fuel pool, or the fuel building atmosphere. 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 total weight of 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 fresh fuel assembly being misplaced within a Region 2 storage cell intended to be empty or intended to hold a low-reactivity spent fuel assembly. 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 light load handling system will continue to meet its current licensing basis with respect to the requirements of GDCs -61 and -62 for radioactivity releases and prevention of criticality accidents. Therefore, FPL finds the proposed EPU acceptable with respect to the light load handling system.

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 Review Standard for Extended Power Uprates does not explicitly call out the Standard Review Plan 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 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 non-safety-related.

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-EPU within the existing operating limits of the current permit.

Condenser cooling water is provided by the CWS which consists of intake and discharge pipes in the ocean with canals to the plant. Pumps at the intake structure provide 484,000 gpm of flow. The circulating water is taken from the ocean through two 12.0 ft. and one 16.0 ft. ID prestressed concrete pipes, commencing 1200 feet offshore.

From the condenser, the discharged condenser cooling water is transported approximately 500 ft. in a buried pipeline and then about 580 ft. in a canal to State Road A1A. The water passes under a bridge. Once past A1A, the cooling water travels about 1200 ft. in a canal to an outfall structure, located on the western side of the sand dune.

The four circulating water pumps are each sized to provide 25 percent of the cooling water flow for the turbine condenser. The pumps are sized for the maximum condenser heat load and provide sufficient head (40 ft.) to overcome system frictional losses.

In addition to the licensing bases described in the UFSAR, the CWS was evaluated for St. Lucie Unit 1 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 9.2.3. 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 CWS 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 CWS 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 Systems
- 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
- 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
- Environmental impact of circulating water returned to the Atlantic Ocean – LAR Attachment 2, Supplemental Environmental Report
- 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
- 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

CWS flow and operating pressure do not increase under EPU conditions. CWS 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 the 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 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;
- 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 the NRC NUREG-0800, Standard Review Plan (SRP) Section 6.2.1.1.A (Reference 1).

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design basis of St. Lucie Unit 1 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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 following a LOCA.

Leak tightness of the containment system and short and long term performance following a LOCA 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 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 LOCA up to and including a double ended rupture of the largest reactor coolant pipe.

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 cooling capacity of either the containment cooling system or the containment spray (CS) system 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 LOCA 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 system described in UFSAR Section 6.2.2 consists of the CS system and the containment cooling system. The CS system consists of two redundant subsystems each containing a CS pump, shutdown heat exchanger and spray header. The containment cooling system consists of four fan coolers. The CS 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.

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 together provide a minimum of 100 percent containment cooling capability assuming a single failure in either system or in the emergency on-site power supply.

- 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 LOCA 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.

In addition to the licensing basis described in the UFSAR, the containment was evaluated for St. Lucie Unit 1 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 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 the 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 break LOCA inside containment. The impact of LOCA mass & energy (M&E) releases on the containment pressure and temperature are addressed to assure that the containment pressure and temperature remain below their respective design limits. The systems must 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. 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 EPU LOCA analysis are performed using the current version of the NRC approved CONTRANS computer code (Reference 2). 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 6.2.1.3.2, Part A.4.

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 described in LR Section 2.8.4.4, Residual Heat Removal System, the primary function of the shutdown cooling (SDC) heat exchanger is to remove heat from containment. The containment spray (CS) flow through the SDC heat exchanger transfers the heat to the component cooling water (CCW) system.

The current licensing basis for the LOCA M&E releases and containment response is described in the UFSAR, Section 6.2.1.3.2. UFSAR Section 6.2.1.3.2, Part B.1, presents the major input assumptions used to support the UFSAR analysis. In addition to those inputs described in LR Section 2.6.3.1, Mass and Energy Release Analysis for Postulated Loss of Coolant, 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% measurement uncertainty) for the EPU versus currently analyzed reactor core thermal power of 2754 MWt (2700 MWt plus 2.0% measurement uncertainty) prior to implementation of the EPU.
- The containment initial pressure is assumed to be 15.51 psia (0.5 psig plus 0.31 psi uncertainty) for the EPU versus 14.7 psia for the current analysis due to the proposed change to Technical Specification 3.6.1.4.
- The containment free volume is 2.498×10^6 ft^3 for the EPU versus 2.506×10^6 ft^3 for the current analysis due to the addition of a more conservative uncertainty value.
- The containment heat sink areas for the EPU have been reduced by 2% from those assumed prior to the EPU.
- The minimum usable refueling water tank (RWT) volume is 411,260 gallons for the EPU versus 305,600 gallons assumed prior to the EPU.
- The CCW/intake cooling water (ICW) loop, which includes the containment spray, containment fan cooler and shutdown cooling, 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. The cases address break location and the minimum safeguards performance used to define the limiting conditions. Only the limiting 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 (loss of one EDG that is, loss of one emergency core cooling system and containment cooling train).

The containment response for design basis LOCA containment integrity is an American Nuclear Society (ANS) Condition IV event, an infrequent fault. 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.

- GDC-38: In order to satisfy the requirement of GDC-38, the calculated pressure at 24 hours should be less than 50% 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 1 was licensed prior to issuance of the SRP (Reference 1). The methodology used in this analysis is consistent with the methodology identified in the SRP 6.2.1. The methodology presented in the current licensing basis is 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 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 containment pressure/temperature response analysis is performed with a spectrum of cases as described in LR Section 2.6.3.1, Mass and Energy Release Analysis for Postulated Loss of Coolant.

The 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. 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 42.77 psig for the limiting DEHLS case. Also, the acceptance criteria for the containment pressure at 24 hours is 50% of the calculated peak pressure. For this case, the containment pressure at 24 hours is 7.35 psig. Therefore, the acceptance criteria for the peak pressure as well as the pressure at 24 hours are met.

In order to gain analysis margin, the upper range in the Technical Specification (TS) 3.6.1.4, Containment Internal Pressure, is changed from 2.4 psig to + 0.5 psig. Additionally, to be consistent with the results from the analysis for the EPU, the peak calculated containment internal pressure for the design basis LOCA, P_a, in the TS 6.8.4.h, is changed from 39.6 psig to 42.8 psig.

As indicated in LR Table 2.6.1-2, the peak containment vapor temperature of 265.57°F for the limiting DEHLS case exceeds the containment vessel design temperature of 264°F for a short time (approximately 30 seconds). However, for this case, the peak containment vessel temperature is 229°F, which is well within the containment vessel design temperature of 264°F. The peak containment vapor temperature of 261.64°F for the limiting DEDLS case results in a containment vessel temperature of 245°F, both of which are within the containment vessel design temperature. Therefore, for the containment vessel temperature acceptance criterion is met for a LOCA event.

The current containment response (UFSAR Table 6.2-1) results for the containment peak pressure and vapor temperature for a LOCA event are 37.82 psig and 259.47°F, respectively.

The LOCA containment response analysis has been performed as part of the EPU. As illustrated above, the peak containment pressure is below the acceptance limit of 44 psig and pressure at 24 hours is well below 50% of the calculated peak pressure. In addition, the containment vessel temperatures for the limiting DEHLS and DEDLS break cases are well below the containment vessel design temperature of 264°F. Based on the results, the applicable SRP criteria with respect to the containment pressure have been met. The containment vessel temperature criteria 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 (SG) outlet nozzle, upstream of the main steam isolation valves (MSIVs). This location results in the largest possible steam flow for a given break size. The blowdown is limited to one SG due to the reverse flow check valve, which prevents flow from the unaffected side SG. 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 low SG 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 containment spray following an appropriate delay for CS pumps to come up to speed and fill the spray lines.

NRC-approved computer code SGNIII (Reference 3) was used to generate the EPU M&E releases for the MSLB inside containment. SGNIII was also used in the current analysis. The code 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 SG 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, SG, cold leg piping and plena, and SG secondary side. Reverse heat transfer from the intact SG 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 SG 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 peak containment pressure results following a design basis accident (DBA), i.e., 100.3 percent power MSLB inside containment. For the peak pressure case, the most limiting single active failure has been determined to be the failure of one containment spray pump 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% measurement uncertainty) for the EPU versus currently analyzed reactor core thermal power of 2754 MWt (2700 MWt plus 2.0% measurement uncertainty) prior to implementation of the EPU.
- The containment initial pressure is assumed to be 15.51 psia (0.5 psig plus 0.31 psi uncertainty) for the EPU versus 17.1 psia assumed prior to the EPU due to the proposed change to Technical Specification 3.6.1.4.
- The containment free volume is 2.498×10^6 ft^3 for the EPU versus 2.506×10^6 ft^3 assumed prior to the EPU due to the addition of a more conservative uncertainty value.
- The containment heat sink areas for the EPU are reduced by 2% 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 spray pump, (2) failure of a main feedwater pump (MFP) to trip, and (3) failure of an MFIV to close. Containment fan coolers are not credited in any of the MSLB scenarios.

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 SG. In the presence of a negative moderator temperature coefficient, this will increase the peak return to power. It is also conservative to assume no cooling of the core by safety injection. This assumption does not credit 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 20%. The 20% restart power bounds and provides significant margin over the peak restart value generated in the MSLB safety analysis but not as high as it would go 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 the EPU. MSLB M&E release data are generated for three single failure scenarios at 0%, 25%, 50%, 75% and full hot power (HFP) cases, as described in LR Section 2.6.3.2. The peak pressure case that produces the highest containment temperature is used for the equipment qualification (EQ) case. The differences between the environmental qualification (EQ) methodology and peak pressure methodology are as follows:

- The EQ case starts from the lowest initial containment pressure of 13.69 psia which delays the reactor trip.
- The EQ case utilizes the superheat model which super heats the steam as the SG tubes uncover.
- In accordance with the Reference 4, Appendix B, Section 1.b, the EQ case utilizes re-vaporization model which allows 8% of the condensation that collects on the heat sink walls to evaporate.

2.6.1.2.2.3 MSLB Results

The limiting case is the 100.3% power with the failure of one CS pump to start. The EPU peak pressure for the limiting case is 43.08 psig. This is higher than the current peak pressure value of 42.76 psig, but remains below the containment design limit of 44 psig.

As indicated in LR Section 2.6.1.2.1.3, in order to gain margin, the upper range in the TS 3.6.1.4, Containment Internal Pressure, is proposed to be changed from 2.4 psig to + 0.5 psig.

The EPU peak EQ temperature is 398.49°F. This is slightly less than the pre-EPU peak EQ temperature of 404.53°F. The reduction in peak EQ EPU temperature was due to tighter analytical 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 398.49°F exceeds the containment vessel design temperature of 264°F for a short time (approximately 1.3 minutes). However, for this case, the peak containment vessel temperature is 239.4°F, which is well within 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 it has adequately accounted for the increase of mass and energy that would result from the proposed EPU. FPL further concludes that containment heat removal systems will continue to provide sufficient 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 its current licensing basis with respect to 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 the St. Lucie Unit 1 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)	15.51	15.51
Initial Containment Temperature (°F)	120	120
Initial Relative Humidity (%)	45	45
Net Free Volume including a -0.5% uncertainty (ft^3)	2,498,445	2,498,445
Ultimate Heat Sink/Intake Cooling Water Temperature (°F)	95	NA
RWT Water Temperature (°F)	104	100(1)
Containment Fan Coolers		
Total	4	NA
Analysis Maximum	4	NA
Analysis Minimum	2	NA
Containment Pressure High Setpoint (psig)	6.3	NA
Delay Time (sec) Without Offsite Power	 30	 NA
Containment Spray Pumps		
Total	2	2
LOCA - Maximum Safeguards	2	NA
MSLB – Failure of MFP to Trip, Failed open MFIV	NA	2
LOCA - Minimum Safeguards	1	NA
MSLB – Failure of Containment Spray Pump	NA	1
Flowrate (gpm) Injection Phase (per pump) Recirculation Phase (per pump)	 2700 2750	 2700 NA
Containment Pressure High-High Setpoint (psig)	11.3	11.3
Delay Time after the Setpoint is Reached (sec) Without Offsite Power With Offsite Power	 63.5(2) NA	 63.5 52

1. The MSLB analysis uses the (maximum) Technical Specification RWT temperature.
2. The LOCA analysis assumes a 1.9 second response time to reach the Containment High-High Setpoint. Therefore, the total delay is 65.4 seconds (1.9 sec + 63.5 sec) from the initiation of the LOCA event.

Table 2.6.1-2
LOCA 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)	42.77 psig @ 18.17 sec	265.57°F @ 18.17 sec	7.35 psig	229°F @ 1449 sec
LOCA DEDLS - (long-term temperature response case)	40.16 psig @ 13.97 sec	261.64°F @ 13.97 sec	7.44 psig	245°F @ 1249 sec
MSLB (peak pressure response case)	43.08 psig	NA	NA	NA
MSLB (EQ case)	NA	398.49°F	NA	239.4°F @ 119 sec
LOCA-Current Analysis	37.82 psig	259.47°F	10 psig	NA
MSLB-Current Analysis	42.76 psig	389.20°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)

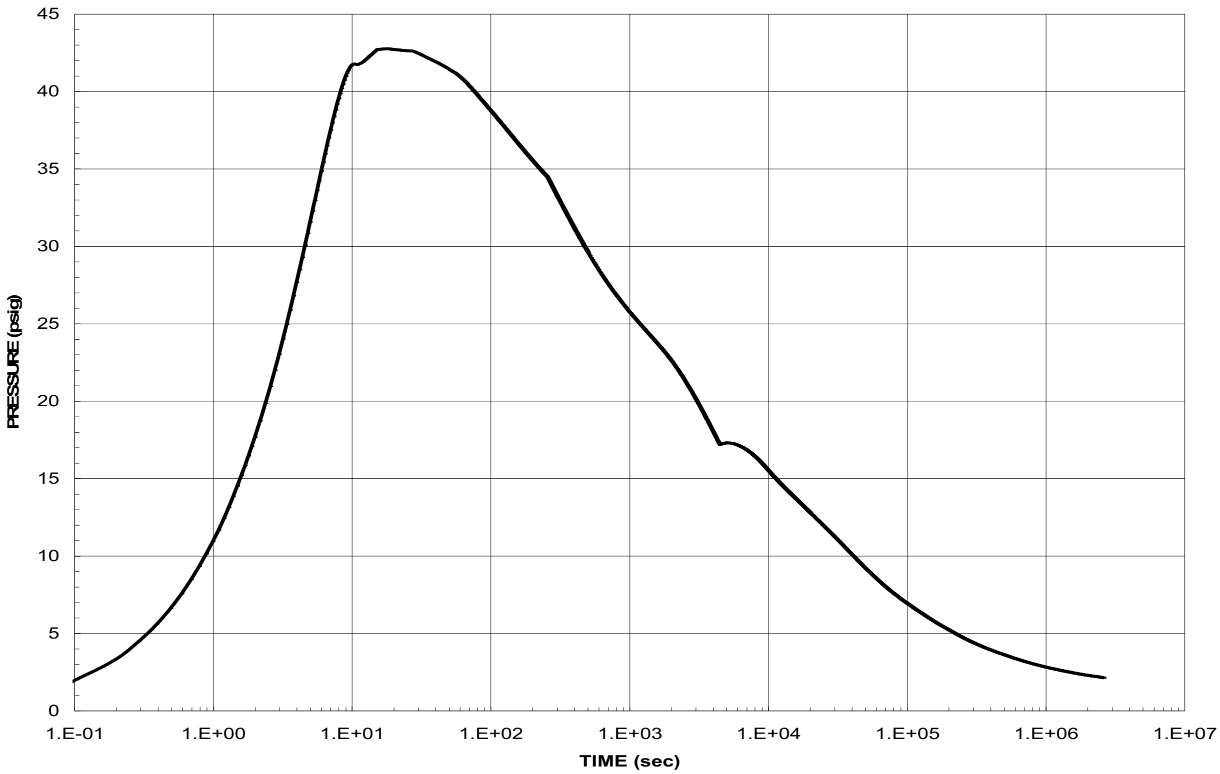


Figure 2.6.1-2
Containment Atmosphere Temperature, LOCA DEHLS
(Peak Pressure Response Case)

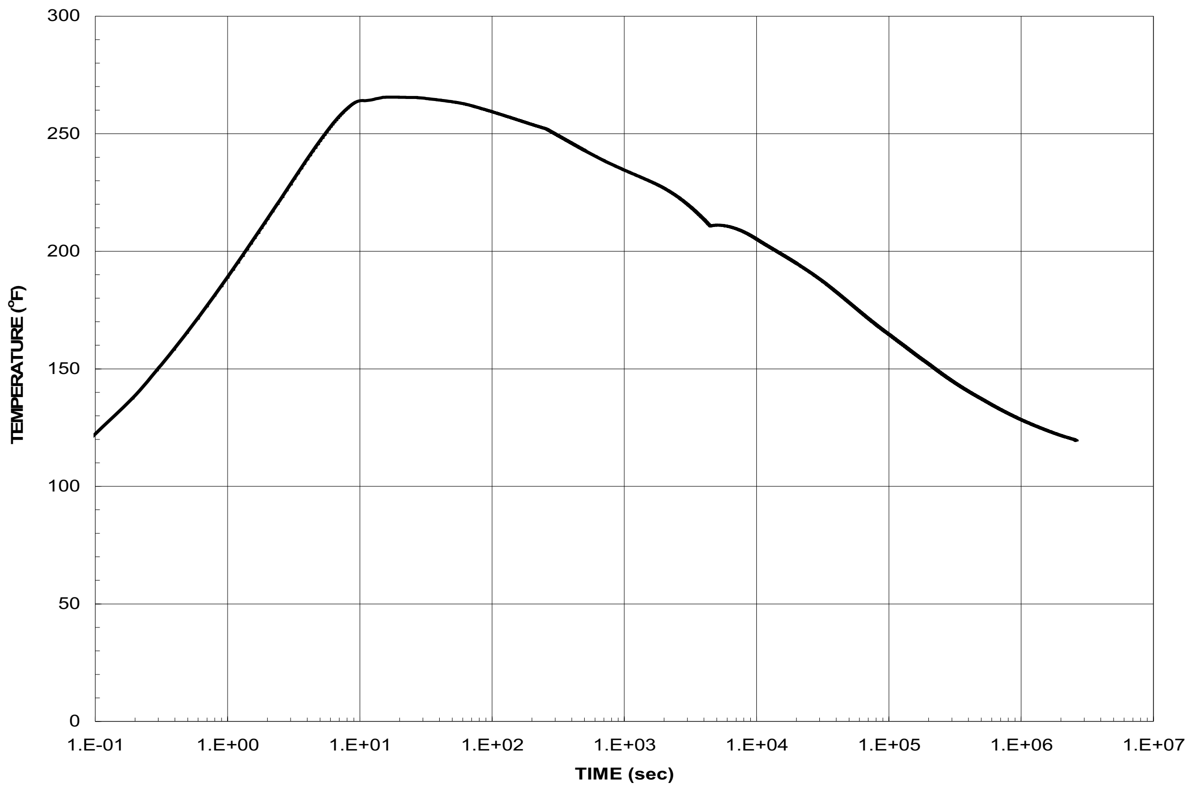


Figure 2.6.1-3
Containment Pressure, LOCA DEDLS
(Long-Term Temperature Response Case)

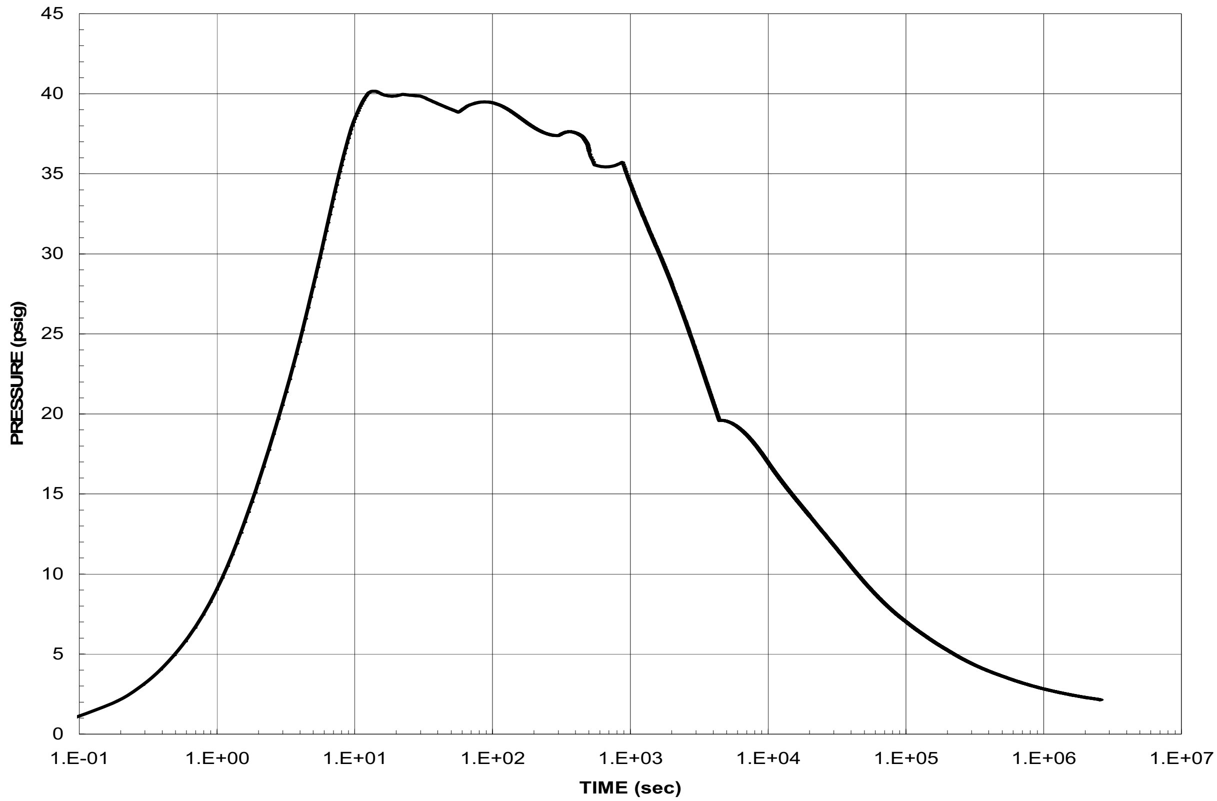


Figure 2.6.1-4
Containment Atmosphere Temperature, LOCA DEDLS
(Long-Term Temperature Response Case)

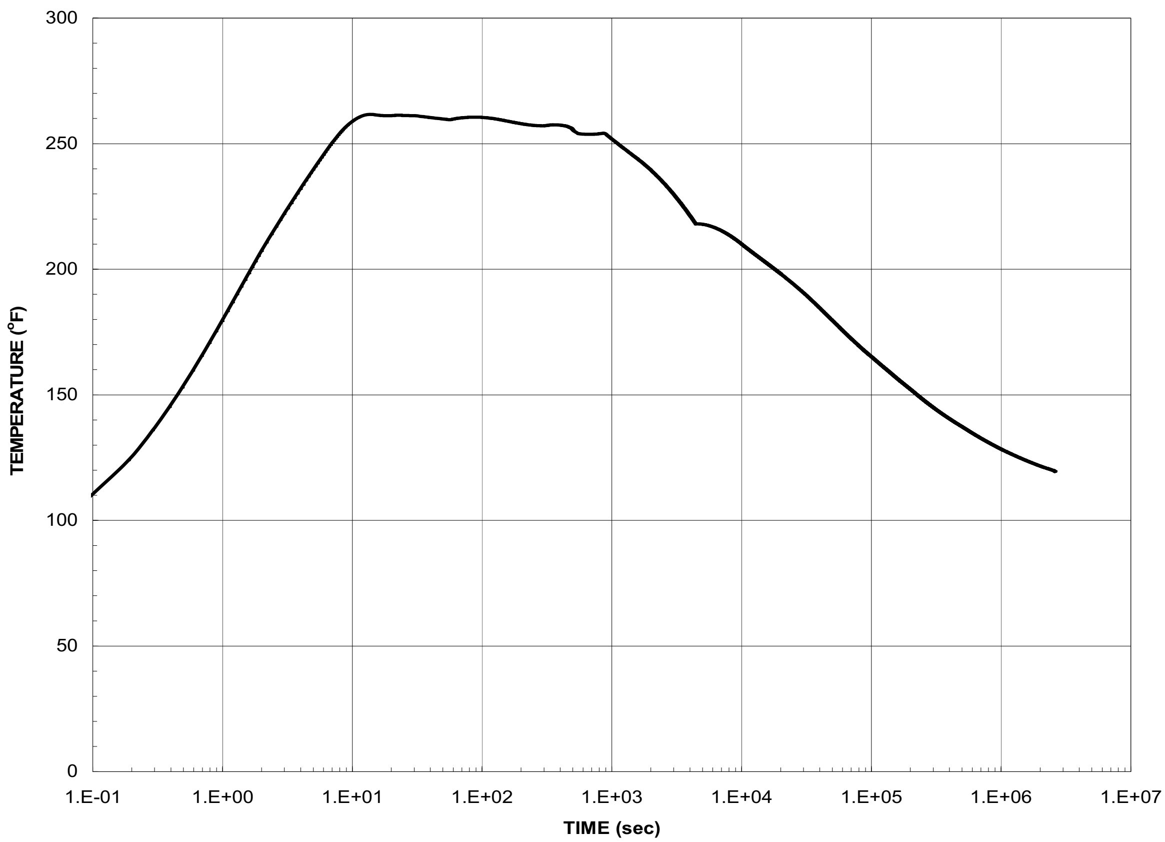


Figure 2.6.1-5
Containment Pressure, MSLB
(Peak Pressure Case)

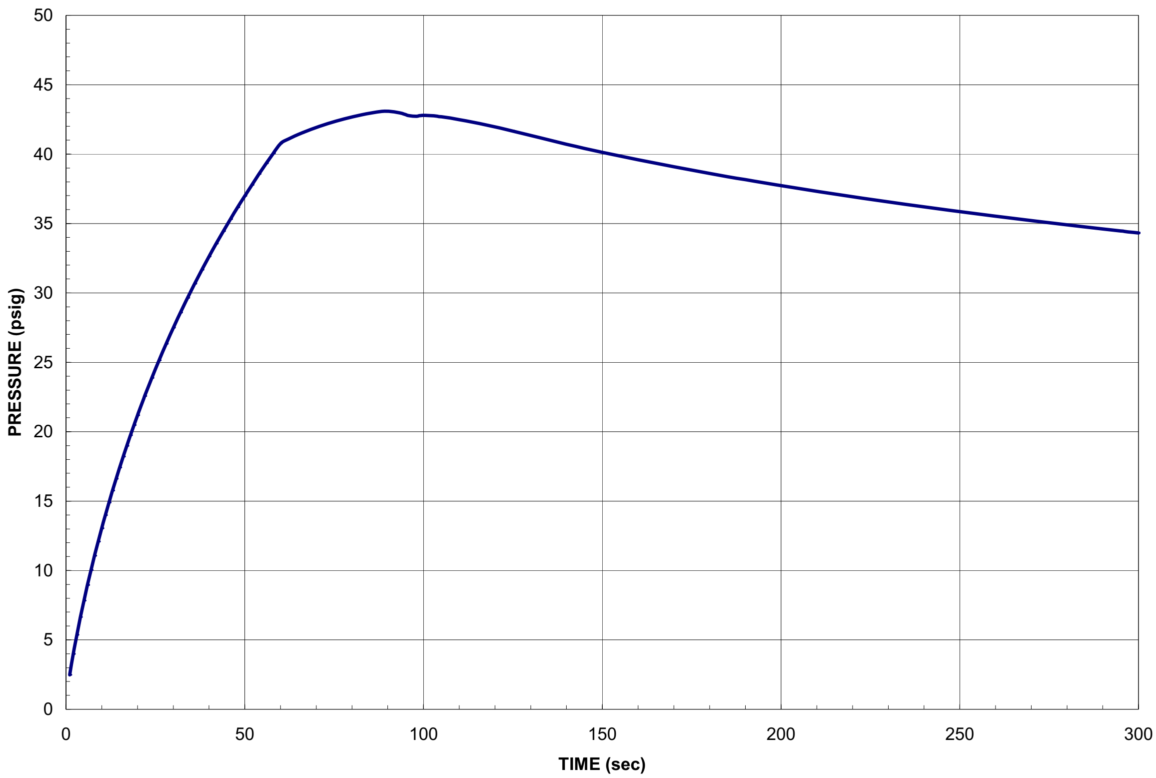
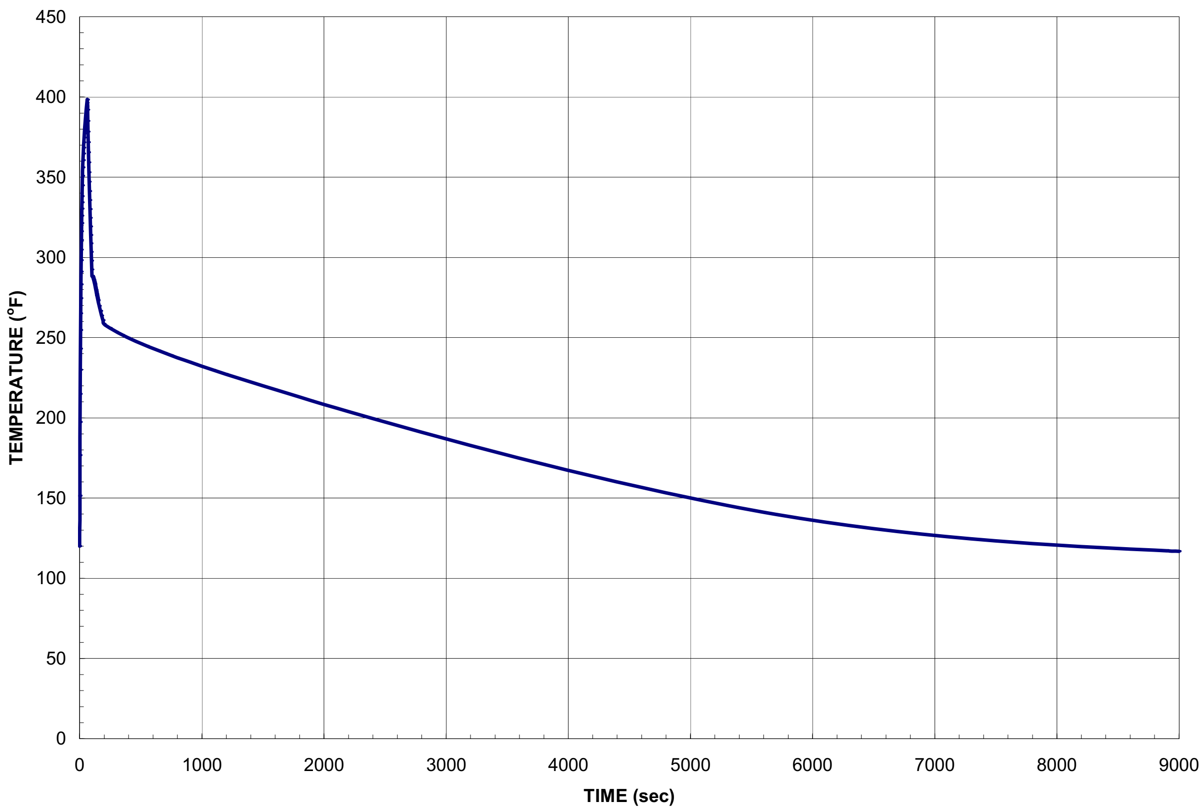


Figure 2.6.1-6
Containment Atmosphere Temperature, MSLB
(Environmental Qualification Case)



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.

FPL's 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 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 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-50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments.

Specific review criteria are contained in SRP Section 6.2.1.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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 (LBB) methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects associated with circumferential (guillotine) and longitudinal (slot) breaks of the RCS loop piping do not have to be considered. A technical evaluation (CE Owners Group Report CON-367-A: Leak-Before-Break Evaluation of Primary Coolant Loop piping in Combustion Engineering Designed Nuclear Steam Supply System) was performed to demonstrate that the probability of such breaks occurring 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. Local missile barriers are 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 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 Class I seismic pipe which causes a 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.

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 Section 3.5, 3.6, 3.7.5 and 3.11 for details.

- 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 (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 LOCA up to and including a double ended rupture of the largest reactor coolant pipe.

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 cooling capacity of either the containment cooling system or the containment spray system 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.

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 General Design Criteria (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. As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie Unit 1 LBB analysis. As a result, compartment pressurization from circumferential (guillotine) or longitudinal (slot) breaks in RCS hot leg or cold leg piping is no longer considered a design basis.

The CONTEMPT code was originally used to calculate the pressure transients resulting from reactor coolant piping breaks within the reactor cavity between the reactor vessel and the primary shield wall, within the enclosed volume inside the secondary shield wall below the operating floor and within the pressurizer cavity. Due to inquiries from the NRC Staff, the same transients have been performed using the RELAP 3 code for the reactor cavity and pressurizer subcompartments. As stated in UFSAR Section 6.2.1.3.3.a, reactor cavity pressurization is no longer a design basis event for St. Lucie Unit 1.

The secondary shield wall analysis is discussed in UFSAR Section 6.2.1.3.3.b. The differential pressure transient across the secondary shield wall is shown in UFSAR Figure 6.2-21.

The pressurizer cavity analysis is discussed in UFSAR Section 6.2.1.3.3.c. The pressure response in the upper pressurizer subcompartment is examined for two break cases; a double ended pressurizer relief line break and a double ended pressurizer spray line break. Since the pressurizer cavity below elevation 62 ft is open to the secondary shield wall subcompartment, that portion of the pressurizer cavity is designed to the same maximum pressure differential as the secondary shield wall, i.e., 24 psid. The UFSAR states that this pressure differential is considered to be greater than that resulting from any pressurizer pipe breaks including the pressurizer surge line.

In addition to the licensing basis described in the UFSAR, the containment, was evaluated for St. Lucie Unit 1 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 pre-EPU licensing basis M&E release remained bounding.

In case that the EPU M&E release was determined to be higher than the pre-EPU 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 6.2.1.3.3, 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:

- 4.0 ft^2 cold leg guillotine break in the reactor cavity
- 3.44 ft^2 hot leg guillotine break in the reactor cavity
- 4.91 ft^2 cold leg slot break in the reactor cavity
- Hot leg double-ended 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 phase.

The initial pressurizer pressure utilized for the pre-EPU M&E release analysis is not impacted by the EPU. Consequently, the current 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 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 5% and the highest initial energy release rate exceeds that of the UFSAR by less than 2%.

3. Pressurizer Surge Line Guillotine Break

The UFSAR does not discuss the pressurizer surge line break; however, the similarity of RCS designs at St. Lucie Unit 1 and 2 supports application of M&E data derived for Unit 2 in an evaluation of subcompartment response at Unit 1.

As documented in LR Section 2.6.3.1, Mass and Energy Release Analysis for Postulated Loss of Coolant, if the pre-EPU St. Lucie Unit 2 pressurizer surge line break M&E release data were adjusted to reflect the higher St. Lucie Unit 1 EPU RCS flow and reduced cold leg temperature, it could be applied to Unit 1 EPU conditions. The resulting EPU St. Lucie Unit 1 M&E release rates were conservatively estimated to increase by less than 0.9% in mass rate and less than 0.4% in energy rate than the pre-EPU St. Lucie Unit 2 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 6.2.1.3.3.b, the secondary shield wall is designed to 24 psid which represents an approximately 40% design margin from the results of the double-ended guillotine break in the hot leg (17.1 psid). This break represents the bounding mass and energy release into the compartment for all postulated RCS pipe breaks within the compartment. The M&E release at the EPU conditions resulting from all other smaller postulated RCS pipe breaks remains bounded by the M&E release utilized for the pre-EPU hot leg double-ended guillotine break. Therefore, the differential pressure across the secondary shield wall structure at EPU conditions is bounded by pre-EPU design basis, and that the current design margin of the structure remains unchanged for EPU conditions.

3. Pressurizer Cavity

As indicated in UFSAR Section 6.2.1.3.3.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 6.2.1.3.3.c, the double-ended pressurizer relief line and pressurizer spray line breaks are considered in the pre-EPU 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. In addition, the EPU pressurizer spray line break initially releases a 4.5% higher mass release rate and a 1.5% 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 ft^2 due to the permanent removal of missile shield roof of the pressurizer cavity which was not considered in the pre-EPU design analyses (refer to UFSAR Section 6.2.1.3.3.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 in UFSAR Section 6.2.1.3.3.c, since the pressurizer cavity below elevation 62 ft is open to the secondary shield wall subcompartment, that portion of the pressurizer cavity is designed to the same maximum pressure differential as the secondary shield wall, i.e., 24 psid. In addition, UFSAR Section 6.2.1.3.3.c states that this pressure differential is considered to be greater than that resulting from any pressurizer pipe breaks including the pressurizer surge line.

  As discussed earlier when evaluating the secondary shield wall, the pre-EPU design basis differential pressure bounds the estimated EPU differential pressure across the secondary shield wall structure for the double-ended guillotine break in the hot leg.

The EPU impact on the estimated differential pressure across the walls of the lower compartment due to a break in the surge line is evaluated based on comparison of the relevant St. Lucie Units 1 and 2 features as discussed below.

a. The configuration of the pressurizer cavity including the internal free volume and vent paths out of the cavity is nearly identical at St. Lucie Units 1 and 2.

b. The pre-EPU St. Lucie Unit 2 pressurizer surge line break M&E release data with a 0.9% increase (conservative with respect to the 0.4% increase calculated for energy), bounds the EPU St. Lucie Unit 1 M&E release data.

c. Per St. Lucie Unit 2 UFSAR Section 6.2.1.2.3, the pre-EPU maximum calculated differential pressure across the lower pressurizer cavity wall for the pressurizer surge line break at St. Lucie Unit 2 is approximately 22.5 psid which is bounded by the St. Lucie Unit 1 design value of 24 psid.

It is conservative to assume that the pressure increase is proportional to the M&E release increase. Thus, the maximum differential pressure is conservatively estimated as approximately 22.7 psid (= 22.5 $\times$ 1.009) at the EPU conditions.

It is concluded that the design margin for the lower pressurizer compartment wall structure at St. Lucie Unit 1 is approximately 6% (= (24 - 22.7)/22.7 $\times$ 100%) 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 and 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 is expected to remain bounded by the M&E release from the pre-EPU hot leg double-ended guillotine break 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 pre-EPU 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 at the EPU conditions is more than compensated by the increased vent path of approximately 190 ft^2 due to the removal of 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% at the EPU conditions based on a comparison of the pressurizer cavity configuration and the limiting surge line break M&E release for St. Lucie Units 1 and 2.

2.6.2.3 Conclusion

FPL has reviewed the subcompartment analyses and the change in predicted pressurization resulting from the increased mass and energy 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 1 will continue to meet its current licensing basis with respect to the requirements of GDC-4 and -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. FPL's 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 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 M&E release analysis to assure that containment design margin is maintained;
- 10 CFR 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 1 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria (GDC) for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Sections 3.1 and 3.2. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the licensing history with respect to the GDC

The specific GDC for the M&E release analysis for postulated LOCA are as follows:

- GDC-50 is described in the UFSAR Section 3.1.50 Criterion 50 – Containment Design Basis.

  As described in this UFSAR section, 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 LOCA up to and including a double ended rupture of the largest reactor coolant pipe.

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 (SI) system is designed such that no single active failure could result in significant metal-water reaction. The cooling capacity of either the containment cooling system or the containment spray system is adequate to prevent over pressurization of the structure, and to return the containment to near atmospheric pressure.

- 10 CFR 50, Appendix K.

  Conformance to Appendix K is addressed in UFSAR Section .4.1.2.3 for the LOCA analyses. Large break LOCAs (LBLOCAs) are analyzed which conform to the modeling requirements of 10 CFR 50, Appendix K. These analyses identify all appropriate sources of energy available for the LBLOCA cases considered and demonstrate conformance to the acceptance criteria of 10 CFR 50.46 to ensure that fuel design limits are not exceeded.

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 St. Lucie Unit 1 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 paragraphs discuss the long-term LOCA M&E releases for the containment used in the containment pressure/temperature response and short-term M&E 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 pre-EPU design analyses, the M&E released into containment during these events has been calculated for the 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, and used in the current licensing basis.

The LOCA M&E analysis was performed using methods that were consistent with the methodology described in UFSAR Section 6.2.1.3.2. 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 SI 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 SI 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 the LOCA event, 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 6.2.1.3.2. Note that the CEFLASH-4A is 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 SI 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 6.2.1.3.2.

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 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, SI flow, and primary and secondary metal mass and SG heat release modeling. UFSAR Section 6.2.1.3.2, Part A.1 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. In addition to those input and assumptions listed in Tables 2.6.3.1-1 through 2.6.3.1-3, the following summarized inputs and assumptions are areas where differences exist between the current licensing analysis and the EPU blowdown M&E release analysis.

- The SRP Section 6.2.1.3.II.1.A (Reference 1) requires that conservatism, such as increasing the RCS and SG secondary mass to account for uncertainties and thermal expansion, be included to maximize the energy release to the containment during the blowdown and reflood phases of a LOCA. Standard practice for the St. Lucie Unit 1 mass and energy release calculations has been to apply a 3% multiplier on all RCS and SG secondary liquid volumes. However, the LOCA M&E release analysis for the EPU applied a 1.5% volume multiplier. The 3% multiplier used historically has been reviewed and found to be overly conservative. The 1.5% multiplier used for the EPU analysis exceeds the maximum expansion of all the RCS component volumes and continues to meet the SRP requirement that uncertainties (manufacturing tolerances) and thermal expansion of the liquid volumes be accounted for. An investigation of the potential effect of uncertainties (tolerances) in the design dimensions used to calculate the cold volumes, which was based on a review of the design drawings, the available as-built dimensions, and the pre-EPU volume calculations, concluded that accounting for the dimensional tolerances would have a negligible impact on the current calculated cold volumes and, consequently, on the LOCA M&E releases.
- The maximum SIT nitrogen gas pressure for the EPU is 280 psig versus 250 psig.

Reflood and Post-Reflood M&E Releases

For the reflood and post-reflood M&E release analysis, heat transfer is conservatively modelled for core, vessel walls, vessel internals, loop metal, SG tubes, SG inventory, and SG secondary walls. UFSAR Section 6.2.1.3.2, Part A.2, presents the major input assumptions used to support the UFSAR blowdown 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 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

Although St. Lucie Unit 1 was licensed prior to issuance of the SRP (Reference 1), the methodology used in this analysis is consistent with the methodology identified in the SRP and used in the current licensing basis of St. Lucie Unit 1. A LBLOCA is classified as an 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 as follows:

- 10 CFR 50, Appendix A
- 10 CFR 50, Appendix K, paragraph I.A

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- 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 ft double ended discharge leg slot (DEDLS) break
- - 9.82 ft double ended suction leg slot (DESLS) break
- - 19.24 ft double ended hot leg slot (DEHLS) break

A review of the results provided in LR Section 2.6.1, Primary Containment Functional Design, 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, Tables 2.6.3.1-4 and 2.6.3.1-5 present the calculated M&E release 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 SI flow. Tables 2.6.3.1-6 and 2.6.3.1-7 presents the calculated break flow and spillages and condensation M&E releases during the reflood/post-reflood phases for the DEDLS with minimum SI flow, respectively.

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are:

- RCS water

- SIT water
- SI 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 SG tubes)
- SG metal (includes transition cone, shell, wrapper, and other internals)
- SG 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)
- End of post-reflood (EOPR)

The M&E inventories for the limiting DEHLS and DEDLS break cases are presented in Tables 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 Tables 2.6.3.1-4 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 Table 2.6.3.1-4 for comparison. As seen from the comparison, the mass release is slightly lower and energy release is higher for the EPU. This is because, for the EPU, the RCS (core) inlet temperature (T_{cold}) 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, in turn, results in a higher enthalpy and lower density break flow. Additionally, a higher SIT gas pressure results in a slightly earlier end of blowdown.

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 1 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 2.1.6, Leak-Before-Break).

Short-term M&E release evaluations are performed to support the pressurizer compartment. With application of LBB, reactor cavity pressurization is no longer a design basis for the plant (UFSAR Section 6.2.1.3.3.a).

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 mass and energy 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 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 currently documented. 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
- Nominal RCS flow rate, including uncertainty

- Nominal full reactor power, including uncertainty

A LOCA is classified as an ANS Condition IV event – an infrequent fault. The relevant requirements to satisfy the acceptance criteria are as follows:

SRP, Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents Subsection II, Part 3a (Reference 1) 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 6.2-5E remain unchanged for EPU.

Spray Line Guillotine Break at Pressurizer Nozzle

A guillotine break of the spray line releases mass and energy 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 6.2-5F 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 5.2% higher mass flux and 1.8% higher energy flux than it does at the conditions of the UFSAR analysis.

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 mass release rate and an energy release rate into the pressurizer subcompartment, that are higher than those in the UFSAR by less than 3% and 1%, respectively.

- 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 5%. The highest initial energy release rate in this range exceeds that of the UFSAR by less than 2%.

Pressurizer Surge Line Guillotine Break at Pressurizer Nozzle

The UFSAR does not discuss the pressurizer surge line break. However, the similarity of RCS designs at St. Lucie Units 1 and 2 supports application of M&E data derived for Unit 2 in an evaluation of subcompartment response at Unit 1. The EPU conditions at St. Lucie Units 1 and 2 have identical values of NSSS power and cold leg temperature (T_{cold}), but different RCS flow rates – 406,966 gpm in Unit 1; 400,756 gpm in Unit 2. The measurement uncertainties in St. Lucie Units 1 and 2 are identical for power, T_{cold} and flow. The higher RCS flow in Unit 1 would produce a lower hot leg temperature, making the surge line break M&E results more adverse.

A guillotine break of the surge line releases mass and energy from both sides of the break – the pressurizer side and the hot leg side.

The M&E release rates from the pressurizer side of a surge line break are dependent only on the initial pressure and liquid enthalpy in the pressurizer. In the short time of interest, the M&E release rates are insensitive to the pressurizer design. The operating pressurizer pressure at EPU in Units 1 and 2 are identical (2250 psia) and the pressurizer is at or near saturation. Therefore, the calculated M&E release rates from the pressurizer side of the break are the same for Units 1 and 2.

The M&E release rates from the hot leg side of a surge line break change with time as the break flow sweeps out the surge line volume and as the cooler (lower enthalpy) fluid from the hot leg itself begins to discharge. The comparison shown in Table 2.6.3.1-10, therefore, reflects the transient or time dependent nature of the difference between the Unit 1 EPU M&E and the current Unit 2 M&E.

Units 1 and 2 have very similar RCS designs. Design differences between their replacement steam generators, reactor vessel upper head and pressurizer have negligible impact on the M&E release rates. Design differences between their surge lines are small, with nearly identical flow losses that would produce nearly identical M&E release rates for the same operating conditions.

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.

2.6.3.1.2.3 Evaluation of 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 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.

2.6.3.1.3 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 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.
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
RCS Total Flow Rate[(1)] (gpm)	375,000
Core/Reactor Vessel Inlet Temperature (°F)	554
Core/ Reactor Vessel Outlet Temperature[(1)] (°F)	608.57
Initial Steam Generator Steam Pressure (psia)	910
Steam Generator Tube Plugging (%)	0
Initial Steam Generator Secondary Side Liquid Mass[(1)] (lbm)	133370
Assumed Maximum Containment Backpressure during reflood (psia)	55
Safety Injection Tank	
Water volume (ft^3) per SIT (average)[(2)]	1162
N_2 cover gas pressure (psig) (maximum)	280
Temperature (°F)	120

1. Core thermal power, RCS total flow rate, RCS coolant temperatures, 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)
15.00	6541.83
17.02	6514.60
23.96	6421.03
56.60	5963.01
85.86	5514.70
111.78	5076.59
134.38	4659.64
153.70	4250.92
169.77	3872.76
182.62	3532.67
191.81	3260.06
198.03	3060.10
201.96	2925.89
202.41	2910.07
202.48	2907.62
204.44	2834.20
208.88	2646.29
212.22	2492.38
214.66	2371.34
220.00	2063.27
224.22	1779.39
226.84	1656.26
230.00	1427.26
231.27	675.61
324.00	648.00
633.00	540.00
839.00	455.00
1045.00	351.00
1148.00	286.00
1158.00	279.00

Table 2.6.3.1-2 (Continued)
SI Flow Maximum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
1162.00	276.00
1251.00	200.00
1303.00	138.00

Table 2.6.3.1-3
SI Flow Minimum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
15.00	3160.17
18.32	3127.03
23.48	3075.51
33.47	2972.58
43.02	2868.78
47.64	2817.43
52.14	2766.11
69.04	2561.15
87.73	2305.67
103.73	2049.97
111.78	1896.52
117.05	1796.07
127.72	1542.94
134.38	1324.47
135.41	1290.68
140.64	1039.15
143.98	738.17
144.37	638.05
144.44	577.03
153.70	574.31
169.77	569.60
182.62	565.83
191.81	563.14
198.03	561.31
201.96	560.16
202.41	560.03
202.48	560.01
315.00	527.00
615.00	420.00
815.00	329.00
1015.00	197.00
1115.00	62.00

Table 2.6.3.1-3 (Continued)
SI Flow Minimum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
1125.00	25.00
1129.00	0.00
1265.00	0.00

Table 2.6.3.1-4
Blowdown Mass & Energy Releases - DEHLS Break

	Mass Rate (lbm/sec)		Energy Rate (BTU/sec)	
Time (sec)	EPU	Current	EPU	Current
0.00	0.00000E+00	0.00000E+00	0.00000E+00	0.00000E+00
0.50	1.04544E+05	1.055043E+05	6.44494E+07	6.404410E+07
1.00	8.52772E+04	8.531561E+04	5.28254E+07	5.193078E+07
2.00	6.89190E+04	7.155847E+04	4.27475E+07	4.295107E+07
3.00	6.03580E+04	6.165763E+04	3.76156E+07	3.741433E+07
4.00	5.16043E+04	5.263487E+04	3.26213E+07	3.236262E+07
5.00	4.37226E+04	4.468704E+04	2.82913E+07	2.790001E+07
6.00	3.38714E+04	3.463632E+04	2.33294E+07	2.279226E+07
7.00	2.35163E+04	2.245482E+04	1.84552E+07	1.742283E+07
8.00	1.65501E+04	1.514488E+04	1.38794E+07	1.285825E+07
9.00	9.26016E+03	9.135906E+03	9.65760E+06	8.892550E+06
10.00	3.63331E+03	3.789557E+03	4.10033E+06	4.307864E+06
10.10	3.24586E+03	3.466377E+03	3.69025E+06	3.948071E+06
10.20	2.84525E+03	3.042139E+03	3.26451E+06	3.494194E+06
10.30	2.51560E+03	2.632125E+03	2.91769E+06	3.058125E+06
10.40	2.21444E+03	2.271513E+03	2.61169E+06	2.661978E+06
10.50	1.91659E+03	1.959227E+03	2.30069E+06	2.311789E+06
10.60	1.66072E+03	1.670240E+03	2.01835E+06	1.987638E+06
10.70	1.44485E+03	1.408400E+03	1.76554E+06	1.694874E+06
10.80	1.24960E+03	1.159889E+03	1.53473E+06	1.408829E+06
10.90	1.08213E+03	9.348827E+02	1.33311E+06	1.143478E+06
11.00	0.00000E+00	7.477443E+02	0.00000E+00	9.192049E+05
11.10	0.00000E+00	5.029643E+02	0.00000E+00	6.193547E+05
11.20	0.00000E+00	0.000000E+00	0.00000E+00	0.000000E+00
INTEGRAL	4.62873E+05	4.667468E+05	3.04235E+08	2.993755E+08
	(lbm)	(lbm)	(BTU)	(BTU)
The end of blowdown is 11.0 seconds for the EPU vs. 11.2 seconds for the current analysis.				

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
0.01	7.51006E+04	4.10883E+07
0.02	7.44669E+04	4.06817E+07
0.03	7.48366E+04	4.08571E+07
0.04	7.56952E+04	4.13273E+07
0.05	8.45197E+04	4.61587E+07
0.06	7.85727E+04	4.29206E+07
0.07	7.74614E+04	4.22947E+07
0.08	7.84992E+04	4.28552E+07
0.09	1.07509E+05	5.87667E+07
0.10	1.08453E+05	5.93118E+07
0.15	1.11939E+05	6.13947E+07
0.20	1.09651E+05	6.02055E+07
0.25	1.08166E+05	5.94257E+07
0.30	1.07769E+05	5.92139E+07
0.35	1.06073E+05	5.82752E+07
0.40	1.06108E+05	5.82891E+07
0.45	1.05195E+05	5.77809E+07
0.50	1.04560E+05	5.74318E+07
0.60	1.03939E+05	5.70975E+07
0.70	1.03379E+05	5.68131E+07
0.80	1.00563E+05	5.52990E+07
0.90	9.71998E+04	5.35023E+07
1.00	9.74095E+04	5.37148E+07
2.00	7.45547E+04	4.24901E+07
3.00	5.48175E+04	3.16045E+07
4.00	4.77191E+04	2.87901E+07
5.00	3.56297E+04	2.36275E+07
6.00	3.28665E+04	2.15538E+07
7.00	2.57661E+04	1.80279E+07
8.00	1.94331E+04	1.49682E+07
9.00	1.27353E+04	1.13226E+07

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	7.69080E+03	7.76118E+06
11.00	6.22773E+03	6.30647E+06
12.00	4.88331E+03	4.94075E+06
13.00	2.06953E+03	2.53507E+06
14.00	1.01689E+03	1.28743E+06
14.10	9.33850E+02	1.19303E+06
14.20	8.67791E+02	1.11164E+06
14.30	8.03195E+02	1.03139E+06
14.40 (EOB)	0.00000E+00	0.00000E+00
INTEGRAL	4.71007E+05 (lbm)	2.95676E+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)
14.30*	0.00000E+00	0.00000E+00
14.40	1.04260E+02	1.36040E+05
17.40	3.95430E+02	5.13110E+05
20.20	6.60860E+02	8.50290E+05
22.20	7.31500E+02	9.36030E+05
22.21	3.65750E+02	4.68015E+05
23.00	3.66400E+02	4.68150E+05
25.80	3.67300E+02	4.67575E+05
28.60	3.66900E+02	4.66005E+05
31.40	3.65880E+02	4.63960E+05
34.20	3.64525E+02	4.61660E+05
37.00	3.62985E+02	4.59220E+05
39.80	3.61335E+02	4.56700E+05
42.60	3.59635E+02	4.54140E+05
45.40	3.57905E+02	4.51565E+05
48.20	3.56165E+02	4.48980E+05
51.00	3.54415E+02	4.46395E+05
53.80	3.52655E+02	4.43810E+05
56.59	3.50895E+02	4.41220E+05
56.60	7.01790E+02	8.82440E+05
72.70	5.53320E+02	6.97310E+05
88.70	4.37270E+02	5.52950E+05
104.70	3.55350E+02	4.50560E+05
120.80	3.01290E+02	3.82660E+05
136.80	2.69290E+02	3.42240E+05
152.80	2.51930E+02	3.20110E+05
168.90	2.43140E+02	3.08710E+05
184.90	2.38980E+02	3.03080E+05
200.90	2.37080E+02	3.00280E+05
217.00	2.36250E+02	2.98810E+05
233.00	2.35930E+02	2.97960E+05
249.00	2.35830E+02	2.97390E+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)
265.10	2.35800E+02	2.96910E+05
281.10	2.35860E+02	2.96510E+05
297.10	2.35920E+02	2.96100E+05
297.20	2.44051E+02	2.89982E+05
299.20	2.39165E+02	3.12010E+05
303.40	2.62266E+02	3.19039E+05
309.70	2.70788E+02	3.44456E+05
318.00	2.73309E+02	3.17300E+05
328.50	2.68405E+02	3.21368E+05
341.00	2.52528E+02	2.94016E+05
355.60	2.38979E+02	2.84066E+05
372.30	2.21830E+02	2.59326E+05
391.10	2.06893E+02	2.44821E+05
412.00	1.92613E+02	2.25744E+05
434.90	1.78828E+02	2.10938E+05
460.00	1.38349E+02	1.62409E+05
487.10	1.21798E+02	1.43496E+05
516.40	1.01333E+02	1.19003E+05
547.70	9.25325E+01	1.08920E+05
547.71 (EOPR)	0.00000E+00	0.00000E+00
INTEGRAL	1.33816E+05 (lbm)	1.65596E+08 (BTU)
* 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 (22.20 seconds) and end at the time when the SITs are empty (approximately 56.50 seconds). 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)
14.30**	0.00	0.00
22.10	0.00	0.00
22.20	5682.24	476956.02
24.20	5379.81	455392.21
26.20	5112.03	436146.77
28.20	4872.00	418792.50
34.90	4213.96	370842.08
39.90	3825.02	342280.15
44.90	3495.19	317945.10
49.90	3209.35	296771.20
54.90	2957.46	278038.52
55.00	331.26	84950.72
56.60	0.00	0.00
297.10	0.00	0.00
317.00	0.00	0.00
317.10	43.67	11193.27
327.10	74.20	19016.65
337.10	101.46	26002.96
347.10	121.85	31228.80
357.10	137.20	35164.11
367.10	148.84	38145.90
377.10	158.12	40525.06
387.10	165.43	42397.31
397.10	171.21	43880.38
407.10	175.92	45087.49
417.10	179.86	46096.54
427.10	183.23	46960.70
437.10	206.00	52796.65
447.10	218.64	56035.98
457.10	228.60	58588.83
467.10	236.65	60651.10
477.10	243.55	62420.66

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)
487.10	249.32	63898.87
497.10	254.14	65134.52
507.10	258.25	66186.52
517.10	261.80	67096.19
527.10	264.90	67892.07
537.10	267.65	68595.85
547.10	270.10	69224.15
547.63	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)	469,939	26,575
Change in RCS inventory (lbm)	0	-443,363
Mass added by 4 SITs (lbm)	0	16,465
Mass added by SI pumps (lbm)	0	0
Mass lost out break to atmosphere (lbm)	0	462,873
Mass lost out break to sump (lbm)	0	0
Error (lbm)		-3,045
Error (%)		-0.658%
		Energy Balance
	Initial	**EOB**
RCS coolant internal energy (BTU)	277,937,400	9,148,023
Change in RCS coolant internal energy (BTU)		-268,789,377
Energy added by 4 SITs (BTU)	0	1,461,196
Energy added by SI Pumps (BTU)	0	0
Heat transferred from fuel (BTU)	0	16,468,000
Heat transferred from RCS walls/internals (BTU)	0	9,790,137
Heat transferred from SG (BTU)		0
Energy lost out break to atmosphere (BTU)	0	304,235,070
Energy lost out break to sump (BTU)	0	0
Error (BTU)		-7,726,360
Error (%)		-2.5%

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)	475,699	19,966	86,182
Change in RCS inventory (lbm)	0	-455,733	-389,517
Mass added by 3 SITs (lbm)	0	15,316	216,100
Mass added by SI pumps (lbm)	0	0	187,893
Mass lost out break to atmosphere (lbm)	0	471,007	662,118
Mass lost out break to sump (lbm)	0	0	131,509
Error (lbm)		42	-117
Error (%)		0.009%	-0.015%
		Energy Balance	
	Initial	**EOB**	**EOPR**
RCS coolant internal energy (BTU)	279,386,700	6,822,493	30,520,474
Change in RCS coolant internal energy (BTU)	0	-272,564,207	-248,866,226
Energy added by 3 SITs (BTU)	0	1,360,079	15,828,947
Energy added by SI Pumps (BTU)	0	0	13,539,963
Heat transferred from fuel (BTU)	0	17,640,000	78,630,149
Heat transferred from RCS walls/internals (BTU)	0	8,282,101	28,275,063
Heat transferred from SG (BTU)	0	-1,380,100	114,241,082
Energy lost out break to atmosphere (BTU)	0	295,675,970	488,429,473
Energy lost out break to sump (BTU)	0	0	9,476,790
Error (BTU)		2,790,317	1,475,168
Error (%)		0.944%	0.296%

Table 2.6.3.1-10
Percentage by Which Surge Line Break M&E Fluxes for EPU at 543°F Exceeds the Fluxes Reported in St. Lucie Unit 2 UFSAR
(Both Sides of Break)

	Event Time of Interest			
	0.25 sec	0.5 sec	1.0 sec	4.0 sec
Mass Flux Difference (%)	< 0.3	< 0.5	< 0.7	< 0.9
Energy Flux Difference (%)	0.1	0.2	< 0.3	< 0.4

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

2.6.3.2.1 Regulatory Evaluation

FPL's 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 criteria for M&E release analysis for secondary system pipe ruptures are based on:

- GDC-50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the values of input parameters.

Specific review criteria are contained in the Standard Review Plan (SRP) (Reference 1) Section 6.2.1.4 and other guidance provided in Matrix 6 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in the UFSAR Section 3.1, the design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the M&E 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 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 cooling capacity of either the containment cooling system or the containment spray system 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 6.2.1.3.2 Part 2B states that the containment pressure and temperature response analysis for the main steam line break (MSLB) event focused on a matrix of cases. This matrix included five different initial power levels and several single failures. The goal of the analysis is to maximize the severity of the mass & energy release, which in turn maximizes the containment pressure and temperature response. The initial plant conditions for the MSLB analysis were selected to maximize the mass and energy release. The initial power levels assumed for this analysis were 102%, 75%, 50%, 25%, and 0% of 2700 MWt. An additional 17.3 MWt was also included for reactor coolant pump heat. Since five power levels were evaluated in this analysis, a number of power dependent inputs were adjusted to conservatively reflect plant conditions for each power level. Presented in UFSAR Table 6.2-4A is a summary of the key inputs and assumptions for the cases considered in this analysis.

UFSAR Section 15.2.8.1.2 states that the feedwater pipe break is a cooldown event in the licensing basis for the plant. As such, the feedwater pipe break event is bounded by the steam line break event for containment analysis since the area for flow in a broken feedwater pipe is less than that of a severed steam line. The smaller area for flow results in a lower steam relief rate which produces a more benign event.

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 St. Lucie Unit 1 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 EPU. The cases that were considered in this analysis are the MSLBs at various power levels ranging from hot zero power to hot full power. Each power level evaluated different single failure scenarios.

2.6.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Assumptions and Input Parameters

The major modeling input parameters and assumptions used in the containment evaluation model for the MSLB event are identified below.

The initial conditions and input assumptions associated with the fan coolers and containment sprays are listed in Table 2.6.1-1, Containment Response Analysis Parameters.

The current licensing basis is described in UFSAR Section 6.2.1.3.2, Containment Vessel Transient Analysis.

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 the UFSAR Tables 6.2-4A and 6.2-4B. In addition to the inputs in USFAR tables, a reactor coolant pump heat input of 20MWt was assumed.

The below summarized inputs and assumptions are areas where the major differences exist between the current licensing analysis and the EPU MSLB M&E release analysis. Note that some containment parameters are also discussed below as the SGNIII code utilizes an iterative process that determines the M&E release, as well as the containment response for a given time step.

- The reactor thermal power is 3030 MWt (rated power of 3020 MWt with 0.3% measurement uncertainty) for the EPU program versus 2754 MWt (102% of 2700 MWt).
- The containment initial pressure was assumed to be 15.51 psia for the EPU versus 17.1 psia for the current analysis. This is due to the proposed change to Technical Specification 3.6.1.4.
- The containment free volume is 2.498×10^6 ft^3 for the EPU versus 2.506×10^6 for the current analysis due to the addition of a more conservative uncertainty value.

Acceptance Criteria

While St. Lucie Unit 1 is not an SRP plant, the acceptance criteria for a MSLB M&E release analysis have been taken from the SRP Section 6.2.1.4 (Reference 1), the relevant requirements considered are as follows:

- Sources of energy
- Mass and energy release rate
- 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) for a base core power at EPU conditions. The evaluation was performed in accordance with NRC's SRP, Section 6.2.1.4 III.2 (Reference 1). The largest break that results in an all steam blowdown was analyzed. The cases that were considered in this analysis are the MSLB at EPU power levels of 0%, 25%, 50%, 75% and 100.3% power.

At each power level, three single failure scenarios were evaluated. Consistent with UFSAR Section 6.2.1.3.2, the following single failure scenarios were evaluated:

- One containment spray (CS) pump fails to operate
- Main feedwater isolation valve (MFIV) fails open
- Main feedwater pump (MFP) fails to trip

Each case was run until the affected steam generator had completed blowdown as indicated by a significant decrease in steam flow out the break.

Each scenario was evaluated to generate the mass and energy releases to calculate the containment pressure and temperature response.

Additionally, a loss of offsite power (LOOP) accident case was evaluated to confirm that it remains bounded by non-LOOP cases.

2.6.3.2.2.4 Evaluation of 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 and temperature response case is the MSLB initiated at hot full power with a failure of one CS pump to start. The M&E releases for the limiting MSLB event are presented in Table 2.6.3.2-1. It was confirmed that this case bounds the results of a LOOP accident.

The results of this analysis (M&E releases rate) are used in the containment integrity analysis (see LR Section 2.6.1, Primary Containment Functional Design).

Table 2.6.3.2-2 provides a sequence of events for the limiting case for current and EPU analyses. Note that the sequence of events changes between the current and EPU analyses. The primary reason for the difference in timing to initiate Auxiliary Feedwater (AFW) is the addition of conservatism by including a harsh environment uncertainty for AFW isolation to the affected steam generator (SG) setpoint (High SGΔP). The addition of the harsh environment uncertainty shifted the current High SGΔP setpoint from 150 psid to 560 psid, resulting in the AFW isolation occurring 8.78 seconds later than the current analysis. As in both the current and EPU analyses, AFW is not initiated until well into the pressure decline of the event. Therefore, the delay in reaching the AFW isolation setpoint does not affect the peak pressure and temperature.

Table 2.6.3.2-2 further shows that there is an approximate 1.3-second delay when comparing analytical setpoints between the current and EPU analyses, such as the reactor trip and SIAS setpoints. This is due to the reduction in the initial containment pressure from the current 17.1 psia to the EPU pressure of 15.51 psia that is described in LR Section 2.6.3.2.2.2.

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, 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)	Current	EPU	Current	EPU
0	6793	6811	8.13E+06	8.15E+06
1	5975	6056	7.17E+06	7.26E+06
2	5383	5499	6.47E+06	6.61E+06
3	4954	5094	5.96E+06	6.13E+06
4	4627	4782	5.57E+06	5.75E+06
5	4381	4543	5.27E+06	5.47E+06
6	4197	4360	5.05E+06	5.25E+06
7	4058	4218	4.89E+06	5.08E+06
8	3938	4107	4.74E+06	4.95E+06
9	3826	4007	4.61E+06	4.83E+06
10	3714	3908	4.47E+06	4.71E+06
11	3603	3806	4.34E+06	4.59E+06
12	3501	3703	4.22E+06	4.46E+06
13	3412	3606	4.11E+06	4.34E+06
14	3339	3519	4.02E+06	4.24E+06
15	3278	3444	3.95E+06	4.15E+06
16	3223	3380	3.88E+06	4.07E+06
17	3169	3321	3.82E+06	4.00E+06
18	3114	3265	3.75E+06	3.93E+06
19	3058	3208	3.68E+06	3.86E+06
20	3005	3152	3.62E+06	3.80E+06
30	2596	2707	3.12E+06	3.26E+06
40	2315	2394	2.78E+06	2.88E+06
50	2062	2152	2.48E+06	2.59E+06
60	1892	1920	2.27E+06	2.30E+06
70	1787	1712	2.14E+06	2.05E+06
80	1312	1531	1.57E+06	1.83E+06
90	312	1205	366984	1.45E+06
100	116	418	136212	492672
110	2.477	145	3182	170454
120	1.888	174	2431	207730
125	1.689	3.584	2176	4514

Table 2.6.3.2-1 (Continued)
Blowdown M&E Release Rates to Containment for the Limiting MSLB

Time (Sec)	Current	EPU	Current	EPU
150	1.302	1.589	1683	2013
200	0.852	1.091	1106	1390
250	0.659	0.794	856	1014
300	0.541	0.628	703	804
INTEGRAL	221115	241536	2.66E+08	2.90E+08
	(lbm)	(lbm)	(BTU)	(BTU)

Table 2.6.3.2-2
Sequence of Events for Limiting Main Steam Line Break Inside Containment for Current and EPU Analyses

Event	Current (Sec)	EPU (Sec)
Break occurs	0.00	0.00
Reactor trip analytical setpoint reached, Containment High Pressure	1.03	2.43
AFW isolation to the affected SG (high SG ΔP) analytical setpoint reached	2.00	10.78
Control Element Assemblies (CEAs) begin entering core	2.43	3.83
SIAS analytical setpoint reached, Containment High Pressure	2.56	3.73
Turbine Stop Valves closed	2.79	4.09
Main Steam Isolation Signal (MSIS) analytical setpoint reached, SG Low Pressure	3.80	5.21
Containment Spray Actuation Signal (CSAS) analytical setpoint reached, Containment High-High Pressure	6.98	8.30
Main Steam Isolation Valve (MSIV) Closure	10.70	12.11
Main Feedwater Isolation Valves closed	22.56	23.73
Containment peak temperature occurs	58.90	60.23
Containment Sprays full on	59.88	60.30
Containment peak pressure occurs	80.02	89.50
AFW to Intact SG initiated	172.00	237.00
End of simulation of the transient	300.00	300.00

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 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 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 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;
- 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 SRP Section 6.2.5.

FPL's review primarily focused on any impact that the proposed EPU may have on the capability to meet the remaining requirements of 10 CFR 50.44 which includes 10 CFR 50.44(b)(1) which requires that St. Lucie Unit 1 continue to possess the capability to ensure a mixed containment atmosphere, and 10 CFR 50.44(b)(4)(ii) which requires that St. Lucie Unit 1 continue to possess the capability to monitor hydrogen in containment.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie

Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

St. Lucie Unit 1 was originally licensed with two redundant electric hydrogen recombiners, located inside containment and a backup 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 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 St. Lucie Unit 1 Technical Specification (TS) 3/4.6.4, Combustible Gas Control. The amendment request was prepared in accordance with the NRC-approved TS 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 St. Lucie Unit 1 TS (Reference 3).

As part of the rulemaking that revised 10 CFR 50.44, the NRC retained the following requirements relative to maintaining combustible gas control inside non-inerted containments.

i. 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 Section 6.2.5.3.1 of the UFSAR, St. Lucie Unit 1 complies with that portion of NRC Regulatory Guide 1.7 regulatory position (Section C.1) which requires a plant to prevent stratification of the atmosphere in the containment following a LOCA. Means to prevent stratification in containment are provided by the containment duct arrangements branching from the containment cooling system ring header duct.

ii. The NRC staff in the notice of availability for this TS improvement requires 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.

In addition to the licensing bases described in the UFSAR, the combustible gas control system was evaluated for St. Lucie Unit 1 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 6.2.5.3 relative to ensuring that stratification of the containment atmosphere following a LOCA does not occur or 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)(4)(ii) assures that St. Lucie Unit 1 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 1 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 1 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 6.2.5.3 or 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, 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), 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) are provided to remove heat from the containment atmosphere and from the water in the containment sump. At St. Lucie Unit 1, the RHR system is referred to as the shutdown cooling (SDC) system.

FPL's 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
- 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 1 Current Licensing Bases

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 LOCA and maintain them at acceptably low levels.

The containment heat removal system 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 redundant subsystems, each containing a CS pump, SDC heat exchanger, and spray header. The containment cooling system consists of four fan coolers and a ducted air distribution system. The CS 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.

UFSAR Section 6.2.2.2.1 further states that with reference to NRC Generic Letter (GL) 2004-02, the containment recirculation sump and recirculation strainer system are designed to provide adequate NPSH margin to the engineered safety features (ESF) pumps during recirculation, considering the postulated debris load, minimum sump water level, and the full range of postulated sump temperatures. NPSH calculations assume fluid at the maximum temperature following start of recirculation with no credit assumed for containment pressure increase above atmospheric. Refer to UFSAR Table 6.2-9A and UFSAR Figure 6.2-29.

Details concerning the SDC system are described in LR Section 2.8.4.4, Residual Heat Removal System. Details on the fan cooling systems are provided in LR Section 2.7.7, Other Ventilation Systems (Containment).

In addition to the licensing basis described in the UFSAR, the containment heat removal systems were evaluated for St. Lucie Unit 1 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 (LR Section 2.6.1, Primary Containment Functional Design) in support of EPU operation. The mass and energy (M&E) release inside containment for both events were also analyzed for the EPU operation. (LR Section 2.6.3.1, Mass and Energy Release Analysis for Postulated Loss of Coolant and Section 2.6.3.2, Mass and Energy Release 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 Section 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 a cooling coil, a fan and a 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 Systems. 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 Systems (Containment).

Any of the following combinations of equipment will provide at least minimum heat removal capability necessary to limit and reduce the post-accident containment pressure and temperature:

a. All four CFCs (100 percent capacity),

b. Both CS subsystems (100 percent capacity),

c. One CS subsystem in conjunction with two CFCs (100 percent capacity).

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. 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 2750 gpm for recirculation mode. These values were used as input for the peak containment pressure-temperature analyses. The design heat removal capacity of a single train of containment spray system (one pump) is 220×10^6 Btu/hr based on 100°F RWT water given a pump flow rate of 2700 gpm.

A single CFC is designed to remove up to 60×10^6 Btu/hr at containment design conditions and a fan flow of 58,000 cfm at an inlet air temperature of 264°F. For the containment LOCA analysis, the 1% 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:

- one CS pump fails to operate,
- a main feedwater isolation valve fails to close, and
- a main feedwater pump fails to trip.

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 265.57°F and the calculated containment peak pressure is 42.77 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 approximately 2°F for approximately 30 seconds, the actual surface temperature of the containment vessel remains below 264°F. 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 43.08 psig and 398.49°F respectively, both resulting from the 100.3% power MSLB with the failure of one CS pump. 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 239.4°F for the 100.3% power MSLB with the failure of one CS pump. 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. FPL reviewed analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The FPL review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure.

The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on:

- 10 CFR 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR 50, Appendix K.

Specific review criteria are contained in SRP Section 6.2.1.5 as provided in Matrix 6 of RS-001, Rev. 0.

St. Lucie Unit 1 Current Licensing

Compliance with the requirements of 10 CFR 50.46 is addressed in UFSAR Section 15.4.1.2.4. The containment pressures are calculated in accordance with Appendix K to 10 CFR 50.

In addition to the licensing bases described in the UFSAR, the ECCS was evaluated for St. Lucie Unit 1 License Renewal. The License Renewal evaluations of each of the systems comprising the ECCS are contained in the specific LR sections for the system. 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 evaluation of the pressure analysis for ECCS performance was determined to be outside the scope of License Renewal.

2.6.6.2 Technical Evaluation

This section discusses the containment backpressure analysis used in the realistic large break loss- of-coolant accident (RLBLOCA) analysis to support an extended power uprate (EPU).

2.6.6.2.1 Introduction

The concurrent containment transient pressure calculation is performed by the ICECON module within the NRC approved RLBLOCA S-RELAP5 code (Reference 1). For the RLBLOCA analysis, the dominant containment parameters, as well as nuclear steam supply system (NSSS) parameters, were established via a phenomena Identification and ranking table (PIRT) process (Reference 1). Other model inputs are generally taken as nominal or conservatively biased. The PIRT outcome yielded two important (relative to peak cladding temperature) containment parameters – containment pressure and temperature. In many instances, the conservative guidance of Containment Systems Branch Technical Position (BTP) 6-1 (Reference 2) was used in setting the remainder of the containment model input parameters. As indicated in LR

Table 2.6.6-1, containment temperature is a sampled parameter. Containment pressure response is indirectly addressed by sampling containment volume, as indicated in LR Table 2.6.6-1. The minimum and the maximum containment volumes are biased to cover a range which would conservatively bound the actual containment volume after accounting for internal structures. The initial conditions and boundary conditions are given in LR Table 2.6.6-1. The containment pressure transient applied is conservatively low and includes the effect of the operation of all pressure reducing systems and processes. The containment pressure as function of time for the limiting case is shown in LR Figure 2.6.6-1.

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 provides the general parameters used in the containment model for RLBLOCA analysis. LR Table 2.6.6-2 provides the structural heat sink data used in the containment model for RLBLOCA analysis. Ongoing processes ensure that the values and ranges used in the ECCS containment backpressure analyses for RLBLOCA bound the values and ranges of the plant as-operated for those parameters.

Acceptance Criteria

As specified in 10 CFR 50, Appendix K, the containment backpressure boundary condition analysis is acceptable if the containment pressure used for evaluating the cooling effectiveness during reflood is calculated conservatively for this purpose. The calculation should include the effects of operation of all installed pressure reducing systems and processes.

2.6.6.2.3 Description of Analyses and Evaluations

The containment backpressure analysis for a RLBLOCA was performed using the ICECON computer code (Reference 3) as sanctioned by the RLBLOCA methodology (Reference 1). These analyses reflect the specific parameters as discussed in LR Section 2.6.6.2.2. The results of the analyses are discussed in LR Section 2.6.6.2.5.

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

The plant systems and components whose performance is relied upon to support the inputs, assumptions and results of the LOCA analyses are discussed in Reference 4. 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

LR Figure 2.6.6-1 provides the plot of the containment pressure curve as a function of time for the limiting case. The containment transient pressure calculation is performed concurrent with the RLBLOCA transient calculation.

2.6.6.3 Conclusion

FPL has assessed the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that the impact has been adequately addressed to ensure that St. Lucie Unit 1 will continue to meet its current licensing basis with respect to the requirements in 10 CFR 50.46 regarding ECCS performance following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to minimum containment pressure analysis for ECCS performance.

2.6.6.4 References

1. AREVA NP Doc. EMF-2103(P)(A), Revision 0, Realistic Large Break LOCA Methodology for Pressurized Water Reactors, April 2003.

2. NUREG-0800, Revision 2, Standard Review Plan, U.S. Nuclear Regulatory Commission, Chapter 6 Engineered Safety Features, Branch Technical Position 6-1, Minimum Containment Pressure Model for PWR ECCS Performance Evaluation, June 1987.

3. EMF-CC-039(P), Supplement 1, Revision 4, ICECON Code Users Manual: A Computer Program Used to Calculate Containment Back Pressure for LOCA Analysis (Including Ice Condenser Plants), AREVA NP Inc, March 2006.

4. AREVA NP Doc. ANP-2903(NP), Revision 0, St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding, February 2010.

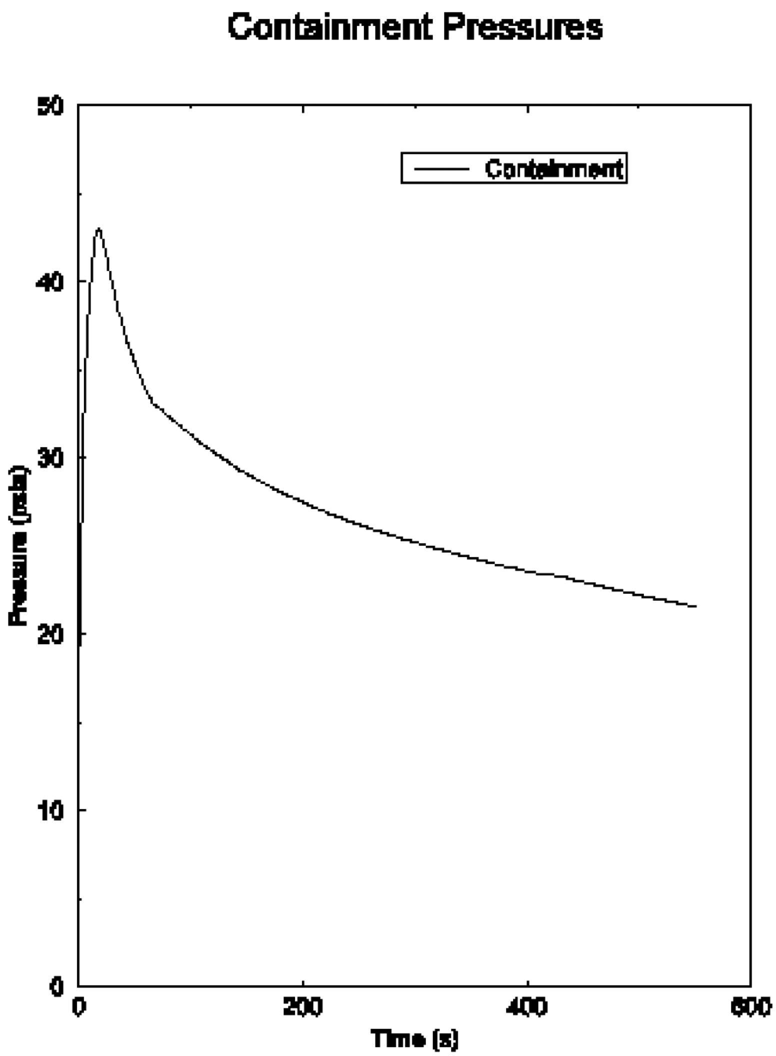
Table 2.6.6-1
Containment Initial and Boundary Conditions

Containment Net Free Volume (ft^3)	2,460,780–2,636,550
Initial Conditions	
Containment pressure (nominal)	14.7 psia
Containment temperature	115.5°F–124.5°F
Outside temperature (enclosure building temperature)	38°F
Humidity	1.0
Containment Spray	
Number of pumps operating	2
Spray flow rate (total, both pumps)	9000 gpm
Minimum spray temperature	36°F
Fastest post-LOCA initiation of spray	0 sec.
Containment Fan Coolers	
Number of fan coolers operating	4
Minimum post-accident initiation time of fan coolers	0 sec.
Fan cooler capacity (1 fan cooler)	
Containment temperature (°F)	Heat removal rate (BTU/sec)
60	0
120	3472
180	8865
220	13,933
264	25,000

Table 2.6.6-2
Structural Heat Sink Data in Containment

Heat Sink	Area (ft^2)	Thickness (ft)	Material
Containment shell	86,700	0.1171	Carbon steel
Floor slab	12,682	20.0	Concrete
Miscellaneous concrete	87,751	1.5	Concrete
Galvanized steel	130,000 130,000	0.0005833 0.01417	Zinc Carbon steel
Carbon steel	25,000	0.03125	Carbon steel
Stainless steel	22,300	0.0375	Stainless Steel
Miscellaneous steel	40,000	0.0625	Carbon steel
Miscellaneous steel	41,700	0.02083	Carbon steel
Miscellaneous steel	7000	0.17708	Carbon steel
Imbedded steel	18,000 18,000	0.0708 7.07	Carbon steel Concrete
Sump steel	7414	0.02895	Carbon steel
Material Properties	**Thermal Conductivity (BTU/hr-ft-°F)**		**Volumetric Heat Capacity (BTU/ft^3-°F)**
Concrete	1.0		34.2
Carbon steel	25.9		53.57
Stainless steel	9.8		54.0
Galvanized	64.0		40.6

Figure 2.6.6-1
Containment Pressure as Function of Time for the Limiting Case



2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

2.7.1.1 Regulatory Evaluation

FPL reviewed the control room habitability system and control room layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. The technical support center (TSC) is located within the control room envelope. The FPL review focused on the effects of the EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination.

The NRC's acceptance criteria for the control room habitability system are based on:

- 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;
- 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 total effective dose equivalent 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the control room habitability 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 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 Sections 3.5, 3.6, 3.7.5 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 (LOCAs). 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.

The design of the control room permits safe occupancy during abnormal conditions. Shielding is designed to maintain tolerable radiation exposure levels (maximum of 3 rem integrated whole body dose over a 90 day period) following design basis accidents (UFSAR Sections 12.1 and 15.4). The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system is designed to recirculate control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 12.2. Radiation detectors and alarms are provided.

UFSAR Section 6.4.1.2 identifies the following as part of the control room habitability system:

- The control room, which provides an envelope for limiting the exposure of control room personnel due to airborne activity and direct radiation from the containment.
- The control room air conditioning and ventilation system.

UFSAR Section 6.4.1.1, as updated by approved-pending changes associated with the NRC-approved Alternative Source Term (AST) amendment, states that the control room habitability systems are designed to:

a. Permit continuous occupancy of the control room during the first 72 hours following a LOCA. This period of habitability is based on the time it would take to change shifts under adverse meteorological conditions following a LOCA.

b. Permit habitability based on outside air inleakage following a LOCA assuming a differential pressure on the exterior walls and roof of the control room resulting from wind. The calculation of the control room activity for any time after the LOCA is described in UFSAR Section 15.4.1.8. The control room dose calculations, which are also discussed in UFSAR Section 15.4.1.8, take credit for iodine removal by both the shield building ventilation system and the control room recirculation subsystem; credit is also taken for dispersion (χ/Q) between the vent pipe and outside air intakes.

c. Keep direct dose, when added to the dose from airborne radioactivity, below the limits imposed by GDC-19 (5 rem total effective dose equivalent) for the course of the accident. The control room ventilation system is sized to remove airborne radioactivity at a rate sufficient to permit 30 days continuous occupancy by an individual.

d. Maintain carbon dioxide (CO_2) levels below one percent and oxygen (O_2) levels at a minimum of 17 percent at all times.

e. Maintain the ambient temperature required for personnel comfort and equipment operation during normal and accident conditions assuming a single active failure.

f. Withstand design basis earthquake loads without loss of function.

g. Provide sufficient portable fire protection equipment to meet the requirements of GDC-19.

UFSAR Section 6.4.1.3, as updated by pending changes associated with the NRC-approved AST amendment, states that the minimum period of control room habitability is based on the time required to monitor and control operation of engineered safety features and their supporting systems, to monitor radioactive releases and to assure that control room personnel do not receive radiation exposure in excess of 5 rem total effective dose equivalent. Under normal meteorological conditions, a shift change could be made within several hours after a LOCA. However, if adverse meteorological conditions existed, this time would be lengthened in proportion to the duration of the postulated adverse condition.

With respect to the CO_2 limit within the control room envelope, UFSAR Section 6.4.1.3 provides an estimate of 7 hours until the limit would be reached with outside air intakes closed. Control room ventilation outside air intakes would be opened prior to reaching this time limit.

LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST) 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 Sections 2.2.2 and 2.2.3, there are no toxic chemical or other non-radiological airborne hazards that could affect control room habitability.

Additional details that define the licensing basis for the control room habitability systems are described in the following UFSAR Sections:

- 7.4 Systems Required For Safe Shutdown
- 9.4.1 Control Room Ventilation
- 12.2 Ventilation
- 15.4 Class 3 Accidents

On September 30, 2008, the NRC approved Amendment 205 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.

On November 26, 2008, the NRC approved Amendment 206 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 St. Lucie Unit 1 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 6.4.1.2 identifies the following as part of the control room habitability system:

- The control room, which provides an envelope for limiting the exposure of control room personnel due to airborne activity and direct radiation from the containment.
- The control room air conditioning and ventilation system. The control room ventilation system limits airborne radioactivity in the control room following a LOCA by recirculating control room air through charcoal filters, air conditions the control room under normal and accident conditions and supplies fresh makeup to maintain safe levels of carbon dioxide and oxygen under normal and accident conditions.

UFSAR Section 6.4.1.1 states that the control room habitability systems are designed to:

a. Permit continuous occupancy of the control room during the first 72 hours following a LOCA. This period of habitability is based on the time it would take to change shifts under adverse meteorological conditions following a LOCA.

b. Permit habitability based on outside air inleakage following a LOCA assuming a differential pressure on the exterior walls and roof of the control room resulting from wind. The calculation of the control room activity for any time after the LOCA is described in Section 15.4.1.8 d. The control room dose calculations, which are also discussed in Section 15.4.1.8 d, take credit for iodine removal by both the shield building ventilation system and the control room recirculation subsystem; credit is also taken for dispersion (χ/Q) between the vent pipe and outside air intakes.

c. Keep direct dose, when added to the dose from airborne radioactivity, below the limits imposed by GDC-19 (5 rem total effective dose equivalent) for the course of the accident.

The control room ventilation system is sized to remove airborne radioactivity at a rate sufficient to permit 30 days continuous occupancy by an individual.

d. Maintain CO_2 levels below one percent and O_2 levels at a minimum of 17 percent at all times.

e. Maintain the ambient temperature required for personnel comfort and equipment operation during normal and accident conditions assuming a single active failure.

f. Withstand design basis earthquake loads without loss of function.

g. Provide sufficient portable fire protection equipment to meet the requirements of GDC-19.

The control room ventilation system is discussed in LR Section 2.7.3, Control Room Ventilation 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 the 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. There are no additional openings that would provide a leakage path to the control room envelope. The EPU control room dose analyses are presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST). 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 (AST) 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. 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 control room operators against the effects of accidental releases of toxic or 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

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 FPL review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits.

The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on:

- 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 total effective dose equivalent 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 quantity 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;
- 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 1 Current Licensing Bases

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 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 design of the control room permits safe occupancy during abnormal conditions. The control room will be isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system is designed to recirculate control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 12.2. 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.

The shield building ventilation system 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 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 iodine removal system and the containment spray system are designed to operate in conjunction to remove radionuclides from the containment atmosphere following a LOCA and thus, minimize the potential dose consequences from a radioactive release. The systems are designed to maintain the containment spray solution pH to achieve rapid absorption of radio-iodines and the removal of iodines from the containment atmosphere.

The shield building ventilation system has suitable redundancy to assure that for onsite or for offsite electrical power system failure, its 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 (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 spent fuel pool is the primary means to control radioactivity in the fuel handling building. The spent fuel pool is designed to withstand a seismic event without the loss of pool water. The spent fuel pool cooling system is designed to withstand postulated tornado driven missiles and a seismic event without loss of the pool water. The spent fuel pool is designed to prevent damage to spent fuel which could result in radioactivity release to the plant operating areas or the public environs. The fuel handling building ventilation system is designed to capture gaseous fission products escaping the spent fuel pool and to release them through charcoal filters to the environment via the fuel handling building exhaust stack.

- 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 LOCA 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.

In addition to the licensing bases described in the UFSAR, the ESF atmosphere cleanup system was evaluated for St. Lucie Unit 1 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 control room ventilation system provides 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 ventilation system is discussed in further detail in LR Section 2.7.1, Control Room Habitability System, and Section 2.7.3, Control Room Ventilation System.

The containment spray system, in conjunction with the iodine removal system, and the shield building ventilation system 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 shield building ventilation system 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 establish and maintain a slight negative pressure in the shield building annulus following a LOCA, mix the shield building 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. The shield building ventilation system 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 sequentially through a demister, HEPA filter, charcoal filter 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 the 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 exhaust air from the area through HEPA and charcoal filter banks before the air is discharged to the atmosphere. Exhaust air monitors, connected to the noble gas monitoring system, measure the airborne effluent from the ECCS area.

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 absorb radioactive iodine, which may be present in the fuel handling building due to diffusion products from the spent fuel pool. The fuel handling building ventilation system is non-safety related, and no credit is taken for filtration during a fuel handling accident.

Radiation detection devices are provided in the plant to monitor normal radiation levels and to detect and annunciate any abnormal radiation condition. The containment atmosphere radiation monitoring system is designed to provide a continuous indication in the control room of the particulate and gaseous radioactivity levels inside the containment. The plant vent radiation monitoring system is designed to representatively sample, monitor, indicate and record the radioactivity level in the plant effluent gases being discharged from the vent pipe, with continuous indication in the control room. The plant airborne radiation monitoring system is supplemented in the monitoring of plant radiation levels by the plant area radiation monitoring system.

2.7.2.2.2 Description of Analyses and Evaluations

Control Room

At EPU conditions, there is no significant increase in either radiation levels or contamination levels that would affect the ability of the control room ventilation system to maintain control room direct dose, when added to the dose from airborne radioactivity, below the limits imposed by GDC-19 (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 analyses are presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST). 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.

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 shield building ventilation system components, air flow rates or associated controls as a result of EPU. Following a LOCA, the shield building ventilation system 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 increases from 65 seconds to 117 seconds for the EPU, which is bounded by the 310 seconds assumed in the dose analysis. Contributors to the increase in time to reach a negative annulus pressure which are included in the EPU analysis are:

- The increased containment pressure and temperature at EPU conditions following a LOCA.
- Shield building ventilation system fan performance at 1 percent emergency diesel generator under frequency.
- Change in computer modeling used for the analysis.

The major contributor to the increase in time to reach a negative pressure in the annulus is the difference in the computer modeling from WA-TEMPT (pre-EPU) to GOTHIC (EPU) along with the inclusion of the radiation heating of the air, which was considered negligible in the pre-EPU analysis presented in UFSAR Section 6.2.1.3.4.

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 +5.3 in. H_2O, which is an increase from the existing 5.0 in. H_2O, 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 shield building ventilation system 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 (AST), demonstrate the effectiveness of the ESF atmosphere cleanup systems to minimize the release of radioactivity to the environment following a LOCA in compliance with GDC-41.

Reactor Auxiliary Building

There are no changes in equipment or airflow as a result of EPU, therefore, EPU does not affect the ability of the ECCS area ventilation system to perform its atmosphere cleanup functions. The offsite dose analyses, presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST), demonstrate the effectiveness of the ESF atmosphere cleanup systems to minimize the release of radioactivity to the environment following a LOCA in compliance with GDC-41.

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 Appendix 6B, charcoal filters in the shield building ventilation system, ECCS area ventilation system and the control room ventilation system are identified as collection points for radionuclides following design basis accidents. As described below, these systems were reviewed with regard to decay heat generation and dissipation following EPU.

<u>Shield Building Ventilation System</u>

The analysis for the shield building ventilation system charcoal filters identifies that, if the shield building temperature were 150°F, the minimum air flow needed to maintain the charcoal filters below 200°F (alarm setpoint) would be 55 cfm with margin as the charcoal desorption temperature is 300°F. With the minimum cooling flow greater than 300 cfm, the actual temperature rise across the charcoal filters is approximately 8°F for a TID-14844 source term.

The existing margin between the currently predicted heat rise at a minimum cooling flow of 300 cfm (i.e., from 150°F to 158°F), and the alarm setpoint (200°F), is more than sufficient to accommodate the approximately 11.85% 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 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. UFSAR Appendix 6B evaluation indicates that the iodine loadings and heating rate are significantly below that encountered in the shield building ventilation system filters and that the charcoal mass is approximately 5 times that found in the shield building ventilation system filters thereby concluding that absorber heating by decay heat is not significant. EPU would not change this conclusion.

Control Room Ventilation System

For the control room filters, there are several factors that are considered in making a comparative assessment of the control room ventilation system charcoal adsorber loading relative to that of the shield building ventilation system. Following a LOCA, the airborne fission products that eventually reach the control room charcoal filters originate from two sources: filtered effluent releases from the shield building ventilation system and unfiltered containment bypass leakage. The net source from these two pathways is less than that which is used to calculate the shield building ventilation system 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 or heat loads per gram of charcoal on the control room filter. In addition, the use of redundant safety-related booster fans ensures that an air flow (2000 cfm vs. 300 cfm), in excess of the minimum shield building ventilation system flow will be maintained for the duration of the event. 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 approximately 11.85% 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 shield building ventilation system filters addressing both the impact of the AST and EPU.

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 impact 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 (AST), 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 occurrences, and design basis accident (DBA) conditions. FPL's review of the CRVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRVS.

The NRC's acceptance criteria for the CRVS are based on

- 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-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 total effective dose equivalent for the duration of the accident;
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 9.4.1.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the CRVS 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 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 Sections 3.5, 3.6, 3.7.5 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 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.

- 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.

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,
- 12.2 Ventilation, and
- 15.4 Class 3 Accidents.

St. Lucie Unit 1 Technical Specification 3/4.7.7, Control Room Emergency Ventilation 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 30, 2008, the NRC approved Amendment 205 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.

On November 26, 2008, the NRC approved Amendment 206 to the operating license, which adopts the alternative source term as allowed in 10 CFR 50.67 and described in Regulatory Guide 1.183.

In addition to the licensing bases described in the UFSAR, the CRVS was evaluated for St. Lucie Unit 1 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 CRVS provides 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 CRVS is designed to:

- Limit control room doses due to airborne activity to within GDC-19 limits
- Maintain the ambient temperature required for personnel comfort during normal conditions
- Permit personnel occupancy and proper functioning of instrumentation and controls during all normal and loss-of-coolant accident (LOCA) conditions assuming a single failure
- Withstand design basis earthquake loads without loss of function
- Permit personnel occupancy during a toxic gas release accident

During normal operation, the CRVS 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, 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. The system is operated post-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 CRVS was evaluated to assure it is capable of performing its 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.
- 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 in 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 CRVS from toxic gas, or smoke.

Compliance with GDC-60 with regard 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 CRVS provides 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 (AST).

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 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 accident conditions. 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 (AST). 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 St. Lucie Unit 1’s 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 any 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 CRVS 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 CRVS will continue to meet 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 CRVS.

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 FPL review focused on the effects of the proposed EPU on the functional performance of the system.

The NRC's acceptance criteria for the fuel handling building ventilation system are based on

- 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 which contain radioactivity be designed with appropriate confinement and containment.

Specific review criteria are contained in SRP Section 9.4.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the fuel handling building ventilation 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-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. 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 discharges to the plant vent, 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 9.4.6 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. Air is discharged to the atmosphere through a prefilter, HEPA filter bank, charcoal adsorbers and out the fuel handling building vent stack.

In addition to the licensing bases described in the UFSAR, the fuel handling building ventilation system was evaluated for St. Lucie Unit 1 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 fuel handling building ventilation system was determined to be outside the scope of License Renewal.

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 9.4.6 and is addressed in UFSAR Section 15.4.3, Fuel Handling Accident.

The fuel handling building ventilation system is designed to reduce plant personnel doses by preventing the accumulation of airborne radioactivity. The system's 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, charcoal adsorbers 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 and recorded.

The fuel handling building ventilation system is non-safety related. No credit is taken for filtration of the airborne gaseous effluent releases during a fuel handling accident in the fuel handling building.

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.

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.

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

As discussed above, the fuel handling building ventilation system was determined to be outside the scope of License Renewal. Therefore, with respect to the fuel handling building ventilation system, the EPU does not impact any License Renewal evaluations.

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. 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. 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 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. Therefore, the 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. FPL's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems.

The NRC's acceptance criteria for the RAB ventilation systems and turbine areas ventilation systems are based on:

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

St. Lucie Unit 1 Current Licensing Bases

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs for the auxiliary and radwaste area and turbine areas ventilation 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 RAB ventilation systems is described in UFSAR Section .4.2 and consists of the following subsystems:

- RAB main ventilation system
- RAB electrical equipment and battery room ventilation system
- RAB miscellaneous ventilation systems

The radwaste area is located inside the RAB and is serviced by the RAB main ventilation system.

In addition to the licensing bases described in the UFSAR, the auxiliary building, radwaste area and turbine areas ventilation systems were evaluated for St. Lucie Unit 1 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 system 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
- withstand design basis earthquake loads without loss of its cooling function of safety-related equipment.

The RAB ventilation systems consists of the main ventilation and various auxiliary systems. The main system ventilates areas such as equipment areas, pump rooms, the waste management system processing and storage areas, chemical and volume control system equipment rooms, laboratories (exhaust only) and all potentially contaminated areas. Ventilation flow is designed to limit the maximum ambient temperature to 104°F within the equipment areas with an outside air temperature of 93°F.

The RAB ventilation systems consist of the following:

- RAB main ventilation system

- RAB electrical equipment and battery room ventilation system
- RAB miscellaneous ventilation systems

The RAB main ventilation system consists of an air supply subsystem and an air exhaust system. The air supply system provides cooling to the low and high pressure safety injections pumps and the containment spray pumps. Under loss of normal power, the redundant supply fans (Train A and Train B) are automatically connected to their associated on-site emergency diesel generator sets through their separate engineered safety features train related power buses. The main ventilation system exhausts from potentially contaminated areas and is discharged through the plant vent stack during normal operation. The exhaust system serves no safety function. Under accident conditions, the 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).

The RAB electrical equipment and battery room ventilation system maintains the ambient temperatures in the electrical equipment rooms, static inverter room, and battery rooms less than 104°F during normal and emergency conditions to ensure proper equipment operation. The electric equipment room and the static inverter room (which is enclosed within the equipment room) are also provided with supplemental cooling from two non-safety-related air conditioners. Upon loss of offsite power, the electrical equipment and battery rooms supply and exhaust fans are automatically connected to the emergency diesel generator set. During an emergency condition that involves a loss of offsite power, the automatic restart of the battery room exhaust fans and the electrical equipment room supply fans ensures that temperatures will not exceed 120°F in any of the rooms. Each battery room ventilation rate has been sized to avoid buildup of hydrogen.

RAB miscellaneous ventilation systems that service the locker room, laundry room, storage room and machine shop areas are ventilated by a once through system consisting of centrifugal supply and exhaust fan system. Areas within the locker, laundry and storage rooms that may contain potential contaminated materials are ventilated through the RAB main ventilation exhaust system and up through the reactor building exhaust stack. Clean exhaust streams are ventilated through HEPA filtration trains into the RAB open areas or to the atmosphere.

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 is provided with a filtered air supply and with wall mounted exhaust louvers for ventilation. Pressure relief dampers are provided to maintain slight positive pressure to maintain a dust-free environment for switchgear equipment operation. The chemical storage area is ventilated by a wall mounted supply fan with an upstream filter and exhaust louver. Because the chemical storage area is not impacted by the EPU, its ventilation is not discussed further.

2.7.5.2.2 Description of Analyses and Evaluations

The RAB ventilation systems and turbine area ventilation 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 control the release of radioactive effluents 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 RAB 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 the areas served by the RAB ventilation systems. No additional batteries were added. EPU does not change the requirements for maintaining hydrogen concentrations in the RAB below allowable limits. EPU does not add equipment within the RAB. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses for additional information and discussion of compliance with GDC-60.

Refer to LR Section 2.7.6, Engineered Safety Feature Ventilation System for additional information regarding ventilation to the ECCS area during accident conditions.

Since the general areas of the turbine building are an open structure design, 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 areas 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 turbine area ventilation to perform their respective design functions. EPU will not diminish the capability of the RAB ventilation systems or turbine area ventilation to meet the requirements of GDC-60.

2.7.5.3 Conclusion

FPL has reviewed the effects of the 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 systems is to provide a suitable and controlled environment for ESF components following certain anticipated transients and design basis accident (DBA). St. Lucie Unit 1 does not have a singular ESF ventilation system; there are several ventilation systems that perform this function. FPL's review focused on the effects of the 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 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:

- 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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.

Refer to UFSAR Sections 3.5, 3.6, 3.7.5, and 3.11 for details.

- 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.

Refer to UFSAR Sections 8.2.1 and 8.3.2 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 licensing bases described in the UFSAR, the ESF ventilation system was evaluated for St. Lucie Unit 1 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), and
- Diesel generator (EDG) building ventilation (described in UFSAR Section 9.4.7).

Other safety-related ventilation systems are discussed in the following LR sections:

- Section 2.7.1, Control Room Habitability System
- Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup
- Section 2.7.3, Control Room Ventilation System
- Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems
- 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, connected to the noble gas monitoring system, 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.

Emergency Diesel Generators Building Ventilation System

The EDG building ventilation system is designed to provide ambient conditions suitable for occupancy when the EDGs are not in operation. The system maintains the EDG rooms at 104°F during normal operation when the emergency generators are not in operation. When the EDGs are in operation, the fans serving the engine cooling system radiators provide the ventilation air flow through the building to maintain a temperature of 104°F during emergency conditions.

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 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
- 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 ESF ventilation system is within the scope of License Renewal. Operation of the ESF 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.

2.7.6.2.4 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, connected to the noble gas monitoring system, 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 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 1 will continue to meet the current licensing basis with respect to GDC-60. The effects of potential releases to the environment are evaluated in LR Section 2.10.1, and 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 airborne particulate material accumulation is not impacted.

2.7.6.3 Conclusion

FPL has reviewed the effects of the EPU on the ESF ventilation system. FPL has concluded that it has adequately accounted for the effects of the proposed EPU on the ability of the ESF ventilation system 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 control 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 its 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 system.

2.7.7 Other Ventilation Systems (Containment)

2.7.7.1 Regulatory Evaluation

The functions of the containment ventilation systems are to provide heat removal from the containment atmosphere and selected areas within containment, to remove radioactive materials from the containment atmosphere, and to provide containment pressure control under normal and accident conditions. The FPL review of the containment ventilation systems focused on the effects that the EPU will have on the functional performance of the systems.

The acceptance criteria for the containment ventilation system are based on:

- GDC-4, insofar as it requires that safety-related structures, systems, and components 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;
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDCs 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 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 Sections 3.5, 3.6, 3.7.5, 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 LOCA 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 system 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 redundant subsystems each containing a CS pump, shutdown heat exchanger and spray header. The containment cooling system consists of four fan coolers. The CS 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.

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 together provide a minimum of 100 percent containment cooling capability assuming a single failure in either system or in the emergency onsite power supply.

- 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 the containment vessel:

- Containment purge system
- Containment vacuum relief
- Containment fan coolers
- Airborne radioactive removal units
- Reactor support cooling system
- Control element drive mechanism (CEDM) cooling system
- Reactor cavity cooling system
- Hydrogen control system

The containment purge system discussed in UFSAR Section 12.2.2.3, is designed to exhaust the containment atmosphere to the environment. It is rated at 42,000 cfm and is operated following reduction of iodine and particulate activity by the containment airborne radioactivity removal system. It serves to further reduce the residual iodine and particulate activity as well as to reduce the activity of the non-filterable noble gases and tritium.

The containment vacuum relief discussed in UFSAR Section 6.2.1 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 cooling system discussed in UFSAR Section 6.2.2.1, consists of four fan coil cooling units, a ducted air distribution system, and the associated instrumentation and controls. The heat removal capacity of the containment cooling system is adequate to keep the containment pressure and temperature below design values and to bring the containment pressure below 10 psig within 24 hours after any size break in the reactor coolant system (RCS) piping.

The airborne radioactive removal system units discussed in UFSAR Section 12.2.2.2 are designed to remove airborne radioactivity in particulate and iodine form by recirculating containment atmosphere through high efficiency filters and charcoal adsorbers. The system is used for radioactivity removal during normal operation and serves no function for post-LOCA dose reduction.

The reactor support cooling system (in conjunction with the reactor cavity cooling system) discussed in UFSAR Section 9.4.8.3, is designed to limit the temperature of the lubrication plates between the reactor and support leg to 300°F, restrict thermal growth of the reactor vessel supporting steel work to 3/16 inch 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 9.4.8.3 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 9.4.8.1 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 and consequent faulting.

The hydrogen sampling system analyzes the post-LOCA containment atmosphere for potential hydrogen buildup by use of seven sample probe locations and an automatic hydrogen analyzer. If, through sampling, it is determined that the maximum allowable hydrogen concentration limits are being approached, the hydrogen purge system exhausts the containment atmosphere through charcoal filters.

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 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 St. Lucie Unit 1 Technical Specification (TS) 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. The availability of this TS improvement was announced in the Federal Register on September 25, 2003 as part of the consolidated line item improvement process. On February 22, 2008, the NRC approved the requested changes to the St. Lucie Unit 1 TS (Reference 3).

The NRC-approved TS changes eliminated the need for hydrogen recombiners and conformance to GDC-41, GDC-42, and GDC-43 with respect to the combustible gas control system in containment.

TS Section 3/4.6.2, Depressurization and Cooling Systems, ensures that depressurization and cooling capability will be available to limit post-accident pressure and temperature in the containment to acceptable values. During a design basis accident (DBA), at least one containment cooling train and one CS train are capable of maintaining peak pressure and temperature within design limits.

In addition to the licensing basis described in the UFSAR, the containment cooling system was evaluated for St. Lucie Unit 1 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 systems as described above are evaluated for EPU:

- Containment purge system
- Containment vacuum relief
- Containment fan coolers
- Containment airborne radioactivity removal units
- Reactor support cooling system
- CEDM cooling system
- Reactor cavity cooling system
- Hydrogen control system

Refer to LR Section 2.6.4, Combustible Gas Control in Containment for the hydrogen control system.

2.7.7.2.2 Description of Analyses and Evaluations

The existing containment hydrogen purge system will be modified to provide a new function to control containment pressure. As a result, additional restrictions will be imposed on the existing main containment purge system to prohibit its use during power operations. The existing main containment purge system and the modified containment hydrogen purge system are evaluated to examine the requirements for EPU conditions.

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 support cooling systems are capable of performing their intended functions under normal EPU modes.

The containment vacuum relief system was evaluated to ensure that the bounding design parameters (operation of the CS system, containment fan cooler operation, containment maximum normal 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 containment hydrogen purge system is a subsystem of the hydrogen control system. The existing containment hydrogen purge system will be modified to provide a new function to control containment pressure. The modified system will allow the plant to maintain a lower maximum normal operating pressure for EPU. This evaluation describes the operating requirements at EPU.

The containment airborne radioactivity removal units were evaluated to verify that there were no EPU changes that would impact their operation and their ability to remove airborne radioactivity in particulate and iodine form during normal operation.

Other evaluations related to the containment 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
- Radiological consequences analysis – LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST)
- Combustible gas control in containment - LR Section 2.6.4, Combustible Gas Control in Containment
- 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

The existing containment hydrogen purge system will be modified to provide a new function to control containment pressure. To support this function, the two hydrogen purge system exhaust isolation valves will be modified to allow remote-manual control capability. These modified containment isolation valves will automatically close on a containment isolation actuation signal (CIAS) and will be required to close against the maximum differential pressure in the event of a LOCA. Consistent with the treatment of applicable containment isolation valves and containment penetrations, the modified containment isolation valves, as well as the associated containment penetration, will continue to be subject to the requirements of TS 3/4.6.1.1, Containment Vessel – Containment Vessel Integrity; TS 3/4.6.1.2, Containment Systems – Containment Leakage; TS 3/4.6.3, Containment Isolation Valves; TS 3.9.4, Refueling Operations – Containment Penetrations; and TS 3.9.9, Refueling Operations – Containment Isolation System. The modified containment isolation valves will also be subject to the requirements of TS 6.8.4.i, Inservice Testing Program.

Additional restrictions will to require the 48-inch diameter main containment purge system supply and exhaust isolation valves to be closed in Modes 1, 2, 3, and 4 and restrict containment purging to the operation of the containment hydrogen purge system during plant operation. The main containment purge valves and associated containment penetrations will continue to be subject to the TS requirements cited above, as applicable.

The modified containment hydrogen purge system and the existing main containment purge system will continue to maintain pressure boundary integrity. Therefore, the containment purge system will continue to perform its design function following EPU.

Containment Vacuum Relief

The design basis event for the vacuum relief system is the inadvertent initiation of the CS system (both pumps) while all four fan coolers are in operation and the containment is at its maximum normal operating temperature of 120°F. The CS pumps are assumed to reach full runout flow instantaneously, the initial humidity is assumed to be 40 percent and one vacuum relief subsystem is assumed to fail to operate. The RWT water temperature, and therefore the CS water temperature, is assumed to be 60°F as is the component cooling water (CCW) temperature, which is the heat sink for the fan coolers. The shield building annulus initial temperature and humidity are assumed to be 110°F and 100 percent respectively. Containment and annulus initial pressures are 14.7 psia.

The conditions described above are bounding for EPU since they consider the worst case vacuum condition (containment air temperature of 120°F and the RWT and CCW system at 60°F) that would occur when all four containment fan coolers are in operation and both CS pumps actuate instantaneously reaching full runout flow. Following EPU, the containment air temperature will not exceed 120°F and there are no EPU changes that would cause a reduction of temperature in the RWT and CCW system, increase in flow rates or reduction in operating pressure of the CS pumps.

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 RCS piping temperature). The containment air temperature for EPU increased 1.7°F, resulting in a post-EPU containment temperature of approximately 110°F, which is approximately 10°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 it's compliance with GDC-38.

Airborne Radioactive Removal Units

The potential increase in the concentration of radiological contaminants during normal plant operation, which is proportional to the percentage of the uprate, has been evaluated. The potential increase in concentration will not exceed the capability of the airborne radioactive removal units to reduce the airborne contamination for occupational radiation exposure control during normal plant operation under EPU conditions. This system is used for radioactivity removal during normal operation only and serves no function for post-LOCA dose reduction and is not credited in any event analysis. There are no changes to the airborne radioactive removal unit's configuration, components, air flow rates, filter or adsorber efficiencies, or associated controls. Therefore, the airborne radioactive removal units will continue to perform their design function following EPU in compliance with GDC-60.

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.

CEDM Cooling System

EPU results in increased heat loads 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
- 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

A modification to the containment hydrogen purge system will be implemented for EPU. The modification will provide a means for limiting the containment pressure during operation at power. This is necessary in order to support compliance with the proposed change to TS Section 3/4.6.1.4 which will limit positive containment pressure to 0.5 psig; the current limit is 2.4 psig. The modification to the containment hydrogen purge system will provide a new function to limit containment pressure. Additional restrictions will require the main 48-inch diameter containment purge system supply and exhaust isolation valves to be closed in Modes 1, 2, 3, and 4. This section also addresses operation of the containment hydrogen purge system during plant operation. Air operated valve operators that fail closed (no emergency generator impact) will be provided for the existing hydrogen purge containment exhaust isolation valves that will close during a LOCA or steam line break accident and therefore, the dose guidelines of 10 CFR 50.67 will not be exceeded in the event of an accident during purging operations. The only contribution of purge to the activity release is during the short period of time prior to purge isolation at the beginning of the LOCA. The containment isolation valves for the containment hydrogen purge system will be modified to ensure the capability to close against EPU LOCA containment pressure conditions. The modified valves will also be able to isolate containment in less than the 30 seconds assumed in the dose analyses of LR Section 2.9.2. The ability of the modified valves to close against the differential pressure in the event of a LOCA is addressed in LR Section 2.2.4. Also, these containment isolation valves will be controlled from and have indication in the control room.

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 continue to meet design 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.

2.7.7.4 References

1. Federal Register, Volume 68, Page 54123, September 16, 2003.
2. Letter from Gordon L. Johnston (FPL) to NRC, Removal of Hydrogen Recombiners and Analyzers from Technical Specifications, 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), February 22, 2008.

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 & Light (FPL) reviewed the St. Lucie Unit 1 fuel system to ensure that:

- The fuel system is not damaged as a result of normal operation and anticipated operational occurrences (AOOs),
- The 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;
- 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 provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the Saint Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 AOOs.

In ANSI-N 18.2, 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. 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 (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 an adequate protective system. (UFSAR Section 7.2 and Chapter 15)

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 Chapters 4 and 15 of the Safety Analysis Report. 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 AOOs. During non-accident conditions, operation of the plant within LCOs 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 LCOs 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of control element assemblies (CEAs) and soluble boron 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-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:

  - Fuel and clad damage that could interfere with continued effective core cooling is prevented, and
  - 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 ECCS is discussed in detail in UFSAR Section 6.3.2. It consists of the high pressure safety injection subsystem and the low pressure safety injection subsystem and safety injection tanks.

The system is designed to meet the criterion stated above with respect to the prevention of fuel and clad damage that would interfere with the emergency core cooling function for the full spectrum of break sizes, and to the limitation of metal-water reaction. Each of the subsystems is fully redundant, and the subsystems do not share active components other than the valves controlling the suction headers of the high- and low-pressure safety injection pumps. Minimum safety injection is assured even though one of these valves fails to function. These valves are in no way associated with the function of the safety injection tanks.

The ECCS design satisfies the criteria specified in 10 CFR 50, Appendix K. The results of the analyses performed are given in UFSAR Section 6.3.3.

In addition to the licensing basis described in the UFSAR, the fuel system design was evaluated for St. Lucie Unit 1 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 fuel system design was determined to be outside 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

2.8.1.2.1 Fuel System Design Features

The licensing basis for the fuel system design is contained in UFSAR Section 4.2. For EPU, the proven Zircaloy-4 MONOBLOC™ guide tube design is analyzed along with the current Zircaloy-4 standard guide tube design. The MONOBLOC™ guide tube design increases bundle stiffness and therefore improves the mechanical performance of the assembly. The differences in guide tube designs are depicted in LR Figure 2.8.1-1. The other design characteristics remain the same.

The key features of the CE14 HTP fuel assembly are as follows:

- One FUELGUARDTM lower tie plate (LTP),
- One Alloy 718 high mechanical performance (HMP) bottom spacer grid,
- Eight Zircaloy-4 high thermal performance (HTP) spacer grids,
- Four Zircaloy-4 standard or MONOBLOCTM corner guide tubes,
- One Zircaloy-4 instrumentation tube (not a structural component),
- 176 fuel rods featuring Zircaloy-4 cladding and end caps, and
- One stainless steel upper tie plate (UTP) with alloy X750 holddown springs.

The pressure drop, liftoff, and seismic tests performed on CE14 HTP assemblies with MONOBLOC™ guide tubes show minimal differences compared to test results of the current CE14 HTP design, and therefore, the transition to the MONOBLOC™ design does not constitute a mixed core situation from a mechanical analyses perspective.

2.8.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The mechanical analyses performed to support the EPU implementation are based on the following set of input parameters:

- Fuel assembly and rod geometry, dimensions (including tolerances), and material properties for the St. Lucie Unit 1 EPU fuel design described above and for the co-resident fuel in the transition cycles.
- EPU thermal-hydraulic and neutronic operating conditions which include measured reactor coolant system (RCS) flow rate (unchanged as a result of the EPU although the minimum RCS flow rate will be increased from 365,000 gpm to 375,000 gpm) and core inlet temperatures (slight increase from 549°F to 551°F for the EPU), radial and axial power histories, and peaking factors (F_r^T reduced from 1.70 to 1.65).
- UTP, LTP, core support plate, and fuel alignment plate displacement time histories required to generate the seismic models. The EPU will not change the time histories used in the current analysis of record.

As explained in LR Section 2.8.2, Nuclear Design, the power histories were generated from a fuel management analysis representative of the EPU conditions. The actual power histories will vary from cycle to cycle and the criteria impacted by such changes will be reanalyzed on a cycle specific basis using the appropriate input parameters.

The transition to MONOBLOC™ guide tubes is planned for implementation in the first or subsequent EPU cycle. The EPU mechanical analyses, therefore, address both fuel designs.

The mechanical analyses are performed using NRC-approved methodology (References 2 and 3) to evaluate the NRC-approved generic mechanical criteria presented in (Reference 1).

2.8.1.2.3 Description of Analyses and Evaluations

The EPU implementation is evaluated using the NRC-approved generic mechanical criteria (Reference 1). This assessment includes the fuel design changes discussed in LR Section 2.8.1.2.1 and the changes in core operating conditions discussed in LR Section 2.8.1.2.2. The peak rod burnup limit of 62 GWD/MTU is unchanged.

2.8.1.2.3.1 Fuel Rod Analyses

The NRC-approved fuel rod performance models (References 4 and 5) were used to model the anticipated EPU operating conditions and the fuel characteristics of the CE14 HTP design with MONOBLOC™ or standard guide tubes. The fuel rod performance codes model the interrelated effects of temperature, pressure, the mechanical deformation of the fuel and cladding, and fission gas release throughout the entire irradiation history, and therefore, allows the evaluation of the cladding collapse, steady-state and AOOs cladding strain, steady-state cladding stress, cladding corrosion, transient fatigue, and rod internal pressure criteria. Proper tolerances and uncertainties (cladding inner and outer diameters, fuel density, initial backfill pressure, fuel swelling, fuel densification, fission gas release, and/or helium absorption) are considered in each analysis to provide a high level of confidence that each fuel rod design criterion is met. Power histories representative of the EPU fuel management are also processed to include additional conservatisms consistent with References 2 and 3.

2.8.1.2.3.1.1 Internal Hydriding

The absorption of hydrogen by the cladding can result in cladding failure due to reduced ductility and the formation of hydride platelets. This failure mechanism is precluded by controlling the moisture hydrogen impurities in the rod during fabrication. Careful moisture control is applied to minimize the total hydrogen within the fuel rod assemblies.

2.8.1.2.3.1.2 Cladding Collapse

During initial fuel densification, the possibility exists for the formation of axial gaps within the fuel column. Consequently, a cladding creep analysis was performed to verify that the pellet to cladding gap does not close before completion of fuel densification.

The plenum spring was designed to help preclude collapse. The spring accommodates length variation due to initial fuel densification. Furthermore, the pitch of the spring was designed, using stiffening ring relationships, such that collapse in the upper plenum region is prevented.

Cladding collapse calculations were performed and demonstrated that no axial gap within the fuel column can form during the initial densification for all fuel operating in EPU cycles.

2.8.1.2.3.1.3 Overheating of Cladding

To preclude overheating of the fuel rod cladding, analyses were performed to show that the thermal margin criterion for departure from nucleate boiling ratio (DNBR) is satisfied during normal operation and AOOs. This criterion is shown to be met in LR Table 2.8.5.0-10 of LR Section 2.8.5.0, Accident and Transient Analyses.

2.8.1.2.3.1.4 Overheating of Pellets

To prevent overheating of fuel pellets, analyses were performed to show that no pellet centerline melting occurs for normal operation and AOOs. This criterion is shown to be met in LR Table 2.8.5.0-10 of LR Section 2.8.5.0, Accident and Transient Analyses.

2.8.1.2.3.1.5 Stress and Strain Limits

To determine the stresses and strains during transients, ramps to maximum linear heat generation rate conditions were applied to the steady-state power histories. The ramp rates were based on the limits from preconditioning and maneuvering criteria.

In addition to the ramping analysis described above, cladding strain was analyzed in both steady-state conditions and under simulated Condition II events or AOOs. For steady-state conditions, the creep strain at any time throughout life was compared to the strain limit. Simulated AOOs were evaluated to determine the cladding total uniform strain that would occur if a rod was at the maximum allowable power peaking levels. A local power factor times a maximum overpower was applied periodically throughout irradiation.

The steady-state cladding stress analysis was performed considering primary and secondary membrane and bending stresses due to hydrostatic pressure, flow induced vibration, ovality, spacer contact, pellet-cladding interaction, thermal and mechanical bow, and thermal gradients. The applicable stresses in each orthogonal direction were combined to calculate the maximum stress intensities, which were then compared to the applicable ASME Boiler and Pressure Vessel Code design criteria.

An analysis was performed to determine the stresses in the end cap weld area due to the axial load of the pellet stack and plenum spring, and pressure differential during normal operation and AOOs.

The results of the calculations described above confirmed that all stress and strain limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.6 Cladding Rupture

NRC-approved cladding ballooning and rupture models are used in the evaluation of cladding rupture due to a LOCA. Compliance to this criterion is demonstrated in LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents.

2.8.1.2.3.1.7 Fuel Rod Mechanical Fracturing

The accident strength criteria for the fuel assembly structure is that it shall sustain, without impairing coolability or control rod insertability, the forces resulting from seismic and loss of coolant events. The loads arise from inertial forces caused by the motion of the upper and lower core plates, and lateral deflections and impacts transmitted to the assembly through adjacent assemblies, the core plates, and the core baffle. The fuel rod stresses were determined from the combination of stresses due to steady-state operation, lateral spacer impact, and assembly axial impact.

The results of the faulted conditions analysis demonstrated that all stress limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.8 Fuel Densification and Swelling

Fuel densification and swelling are specifically modeled in the NRC-approved fuel rod performance codes (Reference 4) used herein, and thus, are used to demonstrate compliance with the fuel temperature, cladding strain, cladding collapse, and rod internal pressure criteria.

2.8.1.2.3.1.9 Loading Limits

The capability of the fuel rods to withstand normal operation and anticipated operational events was analyzed with NRC-approved fuel rod performance codes (References 4 and 5).

During fluctuations in power, the differential thermal expansion between the guide tubes and the hotter fuel rod cladding may produce tension (during power decrease) or compression (during power increase) in the fuel rod cladding. Using the limiting loads developed from guide tube evaluations, the safety margin to rod buckling is determined.

The results of the fuel rod buckling analysis demonstrated that all loading limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.10 Fatigue

The stresses calculated in the ramping analysis (LR Section 2.8.1.2.3.1.5) were used to evaluate the cladding cumulative fatigue usage through end of life due to cyclic power variations. For conservatism, all cycles were considered to cause extreme maximum stresses for the fatigue evaluation. The transient stress results were evaluated to determine the fatigue usage for each cycle based on the O'Donnel and Langer design curve (Reference 6). These results were accumulated to determine the total fatigue usage factor.

The results of the fuel rod fatigue analysis demonstrated that the fatigue limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.11 Oxidation, Hydriding, and Crud Buildup

Waterside corrosion of the fuel rod cladding is calculated using the NRC-approved corrosion models for Zircaloy-4 (Reference 4). As stated in Reference 1, effects of crud are modeled in the NRC-approved fuel rod performance codes (Reference 4) used herein. The fuel rod corrosion analysis takes into account the methodology changes which occurred as a result of the review and approval of Reference 1.

The results of the fuel rod corrosion analysis demonstrated that all corrosion limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.12 Fuel Rod Growth

Projected fuel rod growth behavior is based on available measured data. The maximum predicted end of life rod growth is calculated using conservative temperatures, worst case dimensional clearance, maximum rod growth, and minimum assembly growth. The fuel rod growth analysis takes into account the methodology changes which occurred as a result of the review and approval of Reference 1.

The results of the fuel rod growth analysis demonstrated that the rod growth limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.1.13 Rod Internal Pressure

Calculation of the rod internal pressure is performed with a NRC-approved fuel rod performance codes (Reference 4). Power histories representative of the EPU fuel management were processed to include conservatisms consistent with NRC-approved methodology (Reference 2). Maximum densification and an NRC-approved bounding fission gas release model are also considered in the rod internal pressure analysis.

The results of the fuel rod internal pressure analysis demonstrated that the pin pressure limit continues to be met for all fuel operating at the EPU conditions when the F_r^T is reduced from 1.70 to 1.65.

2.8.1.2.3.1.14 Fuel Assembly Handling

Handling requirements for the fuel assembly design include acceptable plenum spring axial restraint/compliance. The plenum spring is designed to prevent damage to the fuel column during shipping and handling and to aid in preventing axial gaps in the fuel column during early irradiation. The EPU does not impact this analysis.

2.8.1.2.3.1.15 Fuel Coolability

The loads which arise during faulted conditions from inertial forces caused by the motion of the upper and lower core plates, and lateral deflections and impacts transmitted to the assembly through adjacent assemblies, the core plates, and the core baffle, should not result in fuel assembly deformations which would prevent coolability or the ability to insert control rods. Mechanical analyses were performed to demonstrate that fuel coolability and the ability to insert control rods can be maintained at the EPU conditions.

The results of the faulted condition analysis demonstrated that all limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.2 Fuel Assembly Analyses

2.8.1.2.3.2.1 Stress, Strain and Loading Limits

The structural integrity of the fuel assemblies is ensured by setting design limits on stresses and deformations due to various handling, operational, and accident loads. These limits are applied to the design and evaluation of the assembly component (i.e., UTL, lower tie plate, spacer grids, corner guide tubes, holddown springs, connections, and welds). The capability of the design to withstand possible loads incurred during handling is described in LR Section 2.8.1.2.3.2.8. Acceptability of the assembly to withstand postulated accident conditions is discussed in LR Section 2.8.1.2.3.2.9.

2.8.1.2.3.2.2 Fatigue

Stresses due to the combination of assembly weight, holddown forces, and differential thermal expansion at beginning of life were used to evaluate the guide tube fatigue damage through the end of life due to the cyclic power variations. Cyclic power variations were also used to estimate the fatigue usage factor for the spacer-to-guide tube welds. For conservatism, all cycles were considered to cause the extreme maximum stresses for the fatigue evaluations. The stress results were evaluated to determine the fatigue usage for each cycle based on the O'Donnel and Langer (Reference 6) design curve. These results were accumulated to determine the total fatigue usage factor.

A fatigue analysis was performed and demonstrated that the fatigue limits continue to be met for all fuel assemblies operating at the EPU conditions.

2.8.1.2.3.2.3 Fretting Wear

The prevention of fretting wear induced fuel rod failure in the HTP and HMP spacers is demonstrated by a combination of analysis and fretting tests. Flow test data are used to confirm that fretting related failure will not occur throughout life even with a cladding-to-spacer spring gap.

No fretting related failure is expected at the EPU conditions based on the fretting wear data and grid to rod gap evaluations performed.

2.8.1.2.3.2.4 Oxidation, Hydriding, and Crud Buildup

External corrosion is calculated using an NRC-approved corrosion model (Reference 4) with the inclusion of an enhancement factor. The limiting Zircaloy-4 cage components were analyzed for oxidation and hydrogen pickup. For structural components, the corrosion enhancement factor was selected based on benchmarking data. The hydrogen absorption rate per surface area was applied to the applicable cross-sectional areas of the limiting components.

A cage corrosion analysis was performed and demonstrated that the corrosion limits continue to be met for all fuel operating at the EPU conditions.

2.8.1.2.3.2.5 Rod Bow

As described in Reference 1, the model is based on examinations of post-irradiation rod bow. The potential effect of such bow on thermal margins is covered in LR Section 2.8.3, Thermal and Hydraulic Design.

2.8.1.2.3.2.6 Assembly growth

Projected fuel assembly growth behavior is based on available measured data. The data at all burnups are statistically bounded by the growth prediction curves. For EPU core designs, the fuel assembly growth criterion is met and continued compliance with the mechanical design criteria will be confirmed for each reload cycle design.

2.8.1.2.3.2.7 Liftoff

The design of the holddown springs in the upper tie plate provides sufficient force to prevent fuel assembly liftoff due to hydraulic loads.

Fuel assembly irradiation growth, differential thermal expansion between the assembly and the core support structure, and fuel assembly dimensional tolerances are accounted for in the design. The holddown spring must retain its ability to counteract the hydraulic lift force throughout life. Although a small amount of spring relaxation may occur, this relaxation is compensated for by increased compression due to assembly growth. This allows the holddown springs to continue to provide sufficient holddown force throughout the design life of the fuel.

2.8.1.2.3.2.8 Handling

The assembly design must withstand axial loads from handling operations. The analyses include a load factor times the dry assembly weight to satisfy this criterion. Additional handling requirements for the design include acceptable plenum spring axial restraint/compliance and assembly features to ensure acceptable fuel shuffling characteristics.

Fuel handling analyses were performed and demonstrated that all limits continue to be met at the EPU conditions.

2.8.1.2.3.2.9 Structural Deformations

The accident strength criteria for the fuel assembly structure is that it shall sustain, without impairing coolability or control rod insertability, the forces resulting from seismic and LOCA events. The loads arise from inertial forces caused by the motion of the upper and lower core plates, and lateral deflections and impacts transmitted to the assembly through adjacent assemblies, the core plates, and the core baffle.

A faulted conditions analysis was performed and demonstrated that all limits continue to be met at the EPU conditions.

2.8.1.2.4 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.

2.8.1.2.5 Results

The mechanical analyses have been completed to demonstrate that the generic design criteria (Reference 1) can be satisfied for the CE14 HTP design with Zircaloy-4 MONOBLOC™ guide tubes and CE14 HTP design with Zircaloy-4 standard guide tubes under the planned operating conditions of a core power of 3020 MWt. The mechanical analyses are based on a nominal fuel management representative of the EPU which assumes a F_r^T reduction from 1.70 to 1.65 at full power.

As expected, the increase in power will have an impact on the mechanical design margins. For EPU core designs, the fuel assembly growth criterion is met and continued compliance with the mechanical design criteria will be confirmed for each reload cycle design based on cycle-specific core design.

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 its current licensing basis with respect to the requirements of 10 CFR 50.46, GDC-10, -27, and -35 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the fuel system design.

2.8.1.4 References

1. EMF-92-116(P)(A), Revision 0, Generic Mechanical Design Criteria for PWR Fuel Designs, February 1999.

2. XN-NF-82-06(P)(A), Revision 1, and Supplements 2, 4, and 5, Qualification of Exxon Nuclear Fuel for Extended Burnup, October 1986.

3. ANF-88-133(P)(A), Supplement 1, Qualification of Advanced Nuclear Fuels' PWR Design Methodology for Rod Burnups of 62 GWd/MTU, December 1991.

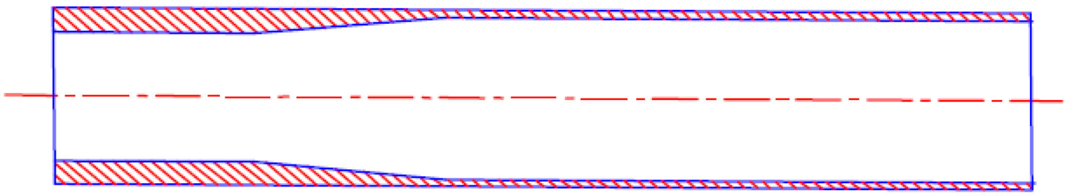
4. XN-NF-81-58(NP), Revision 2, Supplement 3, RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model, January 1983.

5. XN-NF-573, RAMPEX Pellet-Clad Interaction Evaluation Code for Power Ramps, May 1982.

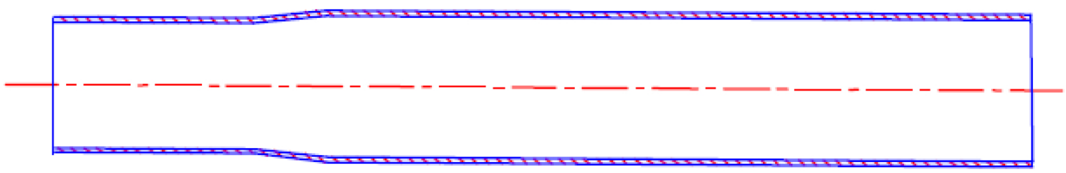
6. W. J. O'Donnel and B. F. Langer, Fatigue Design Bases for Zircaloy Components, Nuclear Science and Engineering, Volume 20, January 1964.

Figure 2.8.1-1
Guide Tube Configuration

MONOBLOC™



Original Configuration



(Not to scale)

2.8.2 Nuclear Design

2.8.2.1 Regulatory Evaluation

Florida Power & 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.

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 specific 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 ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained;
- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB

greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report to the EPU Licensing Report, for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 AOOs.

SAFDLs are stated in UFSAR Section 4.4. Margins to SAFDLs, as prescribed in the Technical Specifications (TS Limiting Conditions for Operation (LCO)), are verified by the safety analyses described in 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, and ensures that SAFDLs will not be violated as a result of AOOs. During non-accident conditions, operation of the plant within LCO ensures that SAFDLs are not approached. Operator action, aided by the control systems and monitored by plant instrumentation, maintains the plant within LCO during non-accident conditions.

- 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 operating range is a decrease in reactivity; i.e., the inherent nuclear feedback characteristics is negative.

The reactivity coefficients are listed in UFSAR Table 4.3-3 and are discussed in detail in UFSAR Section 4.3.1.

- 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 SAFDLs are not possible or can be reliably and readily detected and suppressed.

The effect of the negative power coefficient of reactivity, together with the coolant temperature program maintained by control of regulating rods and soluble boron, provides fundamental mode stability. Power level is continuously monitored by neutron flux detectors (UFSAR Section 7.2.1.1) and by reactor coolant temperature difference measuring devices.

- 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 AOOs, 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 RCPB, 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 liquid level; steam generator level and pressure; and containment pressure and temperature. In addition, instrumentation is provided for continuous automatic monitoring of process radiation level in the reactor coolant system (RCS).

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. Ten independent channels of nuclear instrumentation, which constitute the primary monitor of the fission process. Of these channels, the four wide range channels are used to monitor the reactor from startup through full power; four will monitor the reactor in the power range and are used to initiate a reactor shutdown in the event of overpower.

b. Two independent control element assembly (CEA) position indicating systems

c. A boron dilution alarm, which provides an alarm when a boron dilution event is in progress, is provided as a backup to the primary 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 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 pre-selected operating range.

The containment pressure 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 SAFDLs are not exceeded as a result of AOOS, and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The reactor protective system 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 deenergizing the control element drive mechanism (CEDM) holding latch coils through the interruption of the CEDM power supply. Thus, the CEAs are released to drop into the core reducing reactor power.

The engineered safety features actuation system 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 SAFDLs 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 CEDMs, 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 Sections 15.2.1 and 15.2.2. The reactor protection system will prevent specified acceptable fuel design limits from being exceeded for any anticipated transients.

- 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 AOOs, and with appropriate margin for malfunctions such as stuck rods, SAFDLs 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 SAFDLs 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 AOOs, SAFDLs are not exceeded. The CEAs can be mechanically driven into the core. The appropriate margin for a 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 acceptable fuel design limits are not exceeded.

Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions (UFSAR Section 9.3.4 for details).

- 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of CEAs and soluble boron 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.

During an accident, the safety injection system functions to inject concentrated boric acid into the RCS for long term and short 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 CEAs are divided into shutdown groups and regulatory groups. Administrative procedures and interlocks ensure that only one group is withdrawn at a time, and that 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 7.1.1.

The maximum rate of reactivity addition which may be produced by the chemical and volume control system is too low to induce any significant pressure forces which might degrade the RCPB leak tightness integrity or disturb the reactor vessel internals.

The RCPB described in Chapter 5 and the reactor internals described in Chapter 4 are designed to appropriate codes delineated in the response to Criterion 14. The pressure boundary and internals can 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. UFSAR Section 4.4 discusses the thermal hydraulic design basis that meet the normal and transient plant performance. A summary of the significant thermal and hydraulic parameters is presented in UFSAR Table 4.4-2.

In addition to the licensing basis described in the UFSAR, the nuclear design was evaluated for St. Lucie Unit 1 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 nuclear design was determined to be outside 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 core analysis is to verify that the cycle-specific reload design and the safety input parameters are properly addressed in the reload analysis. The effects of transitioning to the CE14 HTP fuel design with MONOBLOC™ guide tubes and EPU conditions on the nuclear design bases and methodologies for St. Lucie Unit 1 are evaluated in this LR section.

2.8.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The key features of the CE14 HTP fuel design with or without MONOBLOC™ guide tubes fuel assemblies are as follows:

- 0.440 inch outside diameter,
- 136.70 inch active fuel stack length,
- Eight Zr-4 HTP spacer grids,
- Alloy 718 HMP bottom grid,
- Alloy X750 upper tie plate,
- FUELGUARD™ lower tie plate,
- Zr-4 fuel rod clad, and
- Zr-4 guide and instrument tubes.

The CE14 HTP fuel design with MONOBLOC™ guide tubes differs from that of existing CE14 HTP design, with the unique features as described in LR Section 2.8.1, Fuel System Design, only by the use of Zirc-4 MONOBLOC™ guide tubes. Refer to LR Section 2.8.3, Thermal and Hydraulic Design, for discussion of the application of a mixed core penalty to the departure from nucleate boiling (DNBR) safety limits.

Assumptions

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 are expected to be similar to the cycle-to-cycle variations for typical fuel reloads.

Acceptance Criteria

The nuclear design is affected by TS/COLR changes for the EPU conditions as shown in LR Table 2.8.2-1. No changes to the nuclear design philosophy, methods or models are necessary to address CE14 HTP fuel design with MONOBLOC™ guide tubes or the EPU. 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 reload cycle (References 4 and 5). 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 2.8.2-1 provides the EPU values for key safety parameter ranges compared to the current limits.

2.8.2.2.3 Description of Analyses and Evaluations

Standard nuclear design analytical models and methods (References 1 and 6) accurately describe the neutronic behavior of St. Lucie Unit 1 for EPU. The specific design bases and their relation to the GDCs in 10 CFR 50, Appendix A for the CE14HTP design are discussed in Reference 3.

The effect of extended burnup on nuclear design parameters has been previously approved in detail in Reference 2. That discussion is valid for the anticipated discharge burnup level for EPU.

Typical loading patterns, with fuel enrichment limited to 4.6 weight percent (w/o) planar average, were developed based on projected energy requirements listed in LR Table 2.8.2-2. These models show that enough margin exists between typical safety parameter values and the corresponding limits to allow flexibility in designing actual reload cores. Three core designs were developed and used for the majority of calculations performed. Existing designs (including current designs) were used for comparison to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

The first “transition” cycle model was used to capture the initial and predominant transition effects. Appropriate models for the transition (to equilibrium) were developed and used to capture the core characteristics during transition to equilibrium cycle at uprated conditions.

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

Margin to key safety parameter limits (LR Table 2.8.2-1) is not reduced by the CE14 HTP fuel design with or without MONOBLOC™ guide tubes operating at EPU conditions.

Consistent with the analysis assumptions, the changes in fuel design and discharge burnup resulted in only a small impact on the results of the reload transition core analysis relative to the current design. The variations in these parameters are typical of 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 the result of the normal cycle-to-cycle variations in core loading patterns. 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 peaking factor TS can be assured using these methods.

The key safety parameters evaluated for the transition to EPU show little change relative to the current design. The changes in values of the key safety parameters are typical of the normal cycle to cycle variations experienced as loading patterns change.

By keeping the discharge burnup and linear heat generation rate (LHGR) limits unchanged or no increase, there is little increase in the nuclear fuel duty on the assembly. Thus, it follows that assembly based limits are not challenged by operation at EPU conditions. The increase in fresh fuel loading required by increased core thermal power flattens the core radial power shape which mitigates any increase in rod worth that would be expected by the power increase as shown in LR Table 2.8.2-1.

In summary, the changes from the current power fuel core to a core at EPU conditions will not cause changes to the current UFSAR nuclear design bases. Nuclear design methodology is not affected by the transition to EPU.

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 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. EMF-96-029(P)(A), Volumes 1 and 2, Reactor Analysis System for PWRs, Volume 1 Methodology Description, Volume 2 Benchmarking Results, Siemens Power Corporation, January 1997.

2. ANF-88-133(P)(A) and Supplement 1, Qualification of Advanced Nuclear Fuels PWR Design Methodology for Rod Burnups of 62 GWd/MTU, Advanced Nuclear Fuels Corporation, December 1991.

3. EMF-92-116(P)(A), Revision 0, Generic Mechanical Design Criteria for PWR Fuel Design, Siemens Power Corporation, February 1999.

4. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, May 2004.

5. XN-NF-78-44 (NP)(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, Inc., October 1983.

6. WCAP-11596-P-A, Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988 (Westinghouse Proprietary).

Table 2.8.2-1
Range of Key Safety Parameters

Technical Specification	Safety Parameter	Current Values/Limits	EPU Equilibrium Cycle Analysis Values
TS 1.25	Nominal Reactor Core Power (MWt)	2700	3020
TS 3.2.5	Vessel Average Coolant Inlet Temp. HFP (°F)	549 ± 3	551 ± 3
Not a TS	Nominal Coolant System Pressure (psia)	2250	No change
TS 3.1.1.4	Most Positive MTC (pcm/°F)	≤ +7.0 [Power < 70%] ≤ 2.0 [Power ≥ 70%]	No change No change
TS 3.1.1.4 COLR Section 2.1	Least Positive MTC (pcm/°F)	> -32	No change
Not a TS	Doppler Temperature Coefficient (DTC) (pcm/°F)	-2.90 to -0.91	-1.75 to -0.80
Not a TS	Beta-Effective	0.0043 to 0.0072	No change
TS 3.2.3 COLR Section 2.5	Normal Operation F_r^T (without uncertainties)	≤ 1.70	≤ 1.65
TS 3.1.1.1 and 3.1.1.2 COLR Sections 2.8 and 2.9	Shutdown Margin (pcm)	≥ 3600 [> 200 °F] ≥ 2000 [≤ 200 °F]	No change No change
TS 3.2.1 COLR Section 2.4	Linear Heat Rate (kW/ft)	< 15.0	< 14.7
TS 3.2.5 COLR Section 2.6	Axial Shape Index	> -0.08 < 0.15	No change No change
Beta-effective and DTC do not have analyses or TS limits directly associated with them. These parameters are major contributors to transient analysis behavior and are good early indicators of significant physics characteristics changes in the core. Current design values for these parameters are expected ranges only.			

Table 2.8.2-1 (continued)
Range of Key Safety Parameters

Technical Specification	Safety Parameter	Current Values/Limits		EPU Equilibrium Cycle Analysis Values	
Not a TS	**HZP Control Bank Worth**				
	Bank	**Bank Worth (pcm)**		**Bank Worth (pcm)**	
	A	957		884	
	B	436		581	
	6 & 5	629		715	
	7	566		480	
	4	797		630	
	2	763		789	
	1	802		778	
	3	552		389	
	Total	**5501**		**5245**	
	Rod Ejection	**BOL**	**EOL**	**BOL**	**EOL**
Not a TS	Maximum Ejected Rod Worth (pcm)	219.5 (HZP) 12.4 (HFP)	248.8 (HZP) 12.7 (HFP)	180.0 (HZP) 15.2 (HFP)	281.8 (HZP) 16.3 (HFP)
Not a TS	Maximum Ejected Rod $F_Q(Z)$	6.89 (HZP) 2.31 (HFP)	9.65 (HZP) 2.33 (HFP)	4.953 (HZP) 2.058 (HFP)	12.977 (HZP) 1.990 (HFP)
Not a TS	Total Deposited Enthalpy (cal/gm)	26.3 (HZP) 167.1 (HFP)	29.9 (HZP) 168.4 (HFP)	21.2 (HZP) 166.4 (HFP)	29.1 (HZP) 155.9 (HFP)

Table 2.8.2-2
Estimated Transition Cycles Core Characteristics

Transition Cycle	Cycle Energy (EFPH)	Number of Feed Assemblies	HFP ARO Fr	Maximum F_Q (Eq. Xenon)	BOC Beta – Eff	EOC DTC (pcm/°F)
First	12072	84	1.534	1.795	0.006342	-1.395
Second	11928	84	1.544	1.815	0.006331	-1.399
Equilibrium	12000	88	1.535	1.788	0.006380	-1.401

2.8.3 Thermal and Hydraulic Design

2.8.3.1 Regulatory Evaluation

Florida Power & 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 (T-H) instability.

The review also covered hydraulic loads on the core and RCS components during normal operation and design basis accident (DBA) conditions and core T-H stability under normal operation and anticipated transients without scram (ATWS) events.

The Nuclear Regulatory Commission's (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;
- 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 Review Standard (RS)-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report (FSAR), an effort was made to comply with the newer (1971) final GDCs. See Licensing Report (LR) Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the design relative to the GDC is 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.

In ANSI-N 18.2, 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. 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 (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 (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 AOOs. During non-accident conditions, operation of the plant within a 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 a LCO during non-accident conditions.

- 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 SAFDLs are not possible or can be reliably and readily detected and suppressed.

Power level oscillations do not occur. The effect of the negative power coefficient of reactivity, together with the coolant temperature program maintained by control of regulating rods and soluble boron, provides fundamental mode stability. Power level is continuously monitored by neutron flux detectors (UFSAR Section 7.2.1.1) and by reactor coolant temperature difference measuring devices

UFSAR Section 4.4 presents T-H analysis of the reactor core, analytical methods utilized and experimental work for supporting the analytical techniques. The prime objective of the T-H 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 T-H parameters is presented in UFSAR Table 4.4-2. Hydraulic stability is discussed in UFSAR Section 4.4.3.4.

Thermally induced fuel damage during normal steady state and anticipated transient operation is prevented by the T-H design bases. The following are designed for normal operation, anticipated transients and operating occurrences:

- Minimum allowable limits of 1.164 and 1.158 are set on the departure from nucleate boiling ratio (DNBR) during normal operation and any anticipated transients as calculated according to the high thermal performance (HTP) correlation and Modified Barnett correlation, respectively. These two correlations have different ranges of applicability,
- A peak centerline fuel temperature below the melting point, and
- A maximum core void fraction to prevent premature departure from nucleate boiling (DNB).

The primary T-H criteria assure that fuel rod integrity is maintained during normal operation and AOOs. Specific criteria are:

- Avoidance of DNB for the limiting fuel rod in the core with at least a 95% probability at a 95% confidence level, and
- Fuel centerline temperatures remain below the melting point of the fuel pellets.

Observance of these criteria during anticipated operational transients is considered conservative relative to the requirement that anticipated operational transients not produced fuel rod failures or loss of functional capability.

Note 3 of Matrix 8 of Section 2.1 of RS-001 is addressed in LR Section 2.8.3.2.3.

In addition to the licensing basis described in the UFSAR, the T-H design was evaluated for St. Lucie Unit 1 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 adequacy of the T-H 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 T-H analysis supporting the extended power uprate (EPU), which increases the reactor core thermal power from 2700 MWt to 3020 MWt. The current licensing basis for T-H design includes the prevention of DNB on the limiting fuel rod with a 95% probability at a 95% confidence level and criteria to avoid fuel centerline melting. The EPU analysis is based on this licensing basis analysis, incorporating the increased core power. The analysis addresses the DNB performance, including the effects of fuel rod bow and bypass flow. The EPU analysis covers the CE14 HTP fuel design with current standard guide tubes or with MONOBLOC™ guide tubes. The MONOBLOC™ guide tube, has been evaluated to have no significant impact on the pressure drop and T-H characteristics of the core. Thus, the fuel assembly flow area and hydraulic resistance are considered unchanged between the pre-EPU and post-EPU fuel design, so there will be no T-H compatibility or stability issues typically associated with a transition core.

2.8.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

XCOBRA-IIIC is the core T-H sub-channel analysis code that was used for the EPU analysis. NRC approval of the XCOBRA-IIIC code was issued in the safety evaluation report (SER) attached to Reference 1.

For the EPU analysis, fuel-related safety and design parameters used cover CE14 HTP fuel design with current or standard guide tubes or with MONOBLOC™ guide tubes. These parameters have been used in safety and design analyses discussed in this section and in other relevant sections of this LR.

LR Table 2.8.3-1 lists the T-H parameters for the current power level of 2700 MWt, as well as, for the EPU power level of 3020 MWt. Some of the parameters listed in LR Table 2.8.3-1 are used in the analysis basis as XCOBRA-IIIC input parameters, while others are provided since they are listed in UFSAR Table 4.4-2. This section identifies those parameters that are used as input parameters to the XCOBRA-IIIC model and also identifies the limiting direction of each parameter. The following parameters from LR Table 2.8.3-1 are used in the XCOBRA-IIIC model:

- Reactor core heat output (MWt),
- Heat generated in fuel (%),
- Nominal vessel/core inlet temperature (°F),
- F_r, enthalpy rise hot channel factor,
- Pressurizer/core pressure (psia), and
- RCS minimum flow rate (gpm).

The limiting directions for the above parameters are shown in LR Table 2.8.3-2. Biases were applied to input parameters according to the approved methodology (Reference 6). For the transient analyses, uncertainties were deterministically applied. Thus, steady-state measurement and instrumentation errors were taken into account in an additive fashion to ensure a conservative analysis. For statistical DNB calculations, uncertainties were statistically treated according to the approved methodology (Reference 4). The system related uncertainties bounded by the non-loss of coolant accident (LOCA) safety analyses are listed in LR Table 2.8.3-3.

Control grade equipment was modeled in such a way that it does not mitigate the effects of an event. For example, the pressurizer power operated relief valves and pressurizer spray system were assumed operable while the pressurizer heaters were assumed inoperable for DNBR transient events where suppressing primary side pressure is conservative.

The reactor trip setpoints and time delays modeled in the transient analyses were conservatively applied to provide bounding simulations of the plant response. To the extent that the reactor protection system and engineered safety features system is credited in the accident analyses, the setpoints have been verified to adequately protect the plant for EPU operation.

The reactor core is designed to meet the following limiting T-H criteria:

- There is at least a 95% probability at a 95% confidence level that DNB will not occur on the limiting fuel rods during Modes 1 and 2, operational transients, or any condition of moderate frequency; and
- No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.

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 conditions of normal operation, operational transients and transient conditions of moderate frequency.

2.8.3.2.3 Description of Analyses and Evaluations

The T-H analysis of the CE14 HTP fuel is based on the approved methodologies for performing DNB calculations (References 2 and 6). The S-RELAP5 code was used for the transient analysis. The XCOBRA-IIIC code was used to calculate minimum DNBR (MDNBR) using the HTP and Modified Barnett critical heat flux (CHF) correlations. RODEX2-2A (References 10 and 11) was developed to perform calculations for a fuel rod under normal operating conditions. For non-LOCA applications, RODEX2-2A was used to validate the gap conductance used in the analyses and to establish the fuel centerline melt linear heat rate (LHR) as a function of exposure.

The HTP DNB correlation is based entirely on rod bundle data and takes credit for the significant improvements in DNB performance due to the flow mixing nozzles effects. NRC acceptance of a 95/95 HTP correlation safety limit DNBR of 1.141 for the 14x14 HTP fuel assemblies is documented in Reference 3. The Modified Barnett CHF correlation (Reference 7) is used to calculate the DNBR for post-scram reactor conditions. The NRC acceptance of 95/95 Modified Barnett correlation safety limit DNBR of 1.135 is documented in Reference 8. The ranges of parameters used in the EPU design have been verified to fall within the range of applicability for these correlations. A 2% mixed-core penalty is typically applied to DNBR safety limits as required by the SER in Reference 2, which sets the DNBR analysis limits to 1.164 for HTP correlation and 1.158 for Modified Barnett correlation. The power distribution effects are discussed in the specific analyses presented in the 2.8.5 series of LRs.

The approved methodology for performing DNB calculations using the XCOBRA-IIIC code is described in Reference 2. The SER for the Reference 1 topical report states that the use of XCOBRA-IIIC is limited to the “snapshot” mode. Thus, MDNBR calculations were performed using a steady-state XCOBRA-IIIC model with core boundary conditions at the time of MDNBR from the S-RELAP5 transient analyses.

The Reference 4 topical report describes the method for performing statistical DNB analyses. Two conditions were noted in the SER for the Reference 4 methodology:

- The methodology is approved only for Combustion Engineering (CE) type reactors which use protection systems as described in the Reference 4 topical report; and

- The methodology includes a statistical treatment of specific variables in the analysis; therefore, if additional variables are treated statistically, Siemens Power Corporation, now AREVA NP should re-evaluate the methodology and document the changes in the treatment of the variables. The documentation will be maintained by AREVA NP and will be available for NRC audit.

Protection against the fuel centerline melting (FCM) SAFDL is expressed as a limit on LHR allowed in the core. The FCM limit was explicitly calculated for the EPU. Due to the reduced thermal conductivity of gadolinia fuel rods, the FCM limit may be set by gadolinia fuel. A FCM limit is established for UO_2 fuel rods such that, FCM is precluded for all fuel rod types.

The approved methodology for calculating the enthalpy deposition for a control element assembly (CEA) ejection accident is given in Reference 5. No restrictions or requirements were identified in the SER for the Reference 5 methodology.

The impact of rod bowing on the MDNBR and peak LHR was evaluated using the rod bow methodology described in Reference 9. The objective was to determine the threshold burnup level at which a rod bow penalty must be applied to either the MDNBR or peak LHR results. The results show that the threshold burnups are beyond the current licensing limit of 55 GWd/MTU, therefore no rod bow penalty is required for DNB or LHR calculations. Recent fuel rod bow measurements taken on contemporary CE14 HTP fuel designs continue to validate the existing fuel rod bow methodology.

The impact on the guide tube heating was evaluated. The XCOBRA-IIIC code was used to provide the necessary boundary conditions. The uprated conditions were determined to have sufficient margin to boiling in the guide tubes.

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.

2.8.3.2.5 Results

LR Table 2.8.5.0-10 of LR Section 2.8.5.0, Accident and Transient Analyses, summarizes the analysis limits and results for non-LOCA events that were reanalyzed for EPU. The results of the analyses demonstrate that the event-specific acceptance criteria are met for EPU operation. The compliance with the acceptance criteria is verified on a cycle-by-cycle basis as part of the cycle specific reload evaluation.

A mixed core penalty was conservatively included in the DNB analysis limit, even though the EPU core design used in the analyses was not a mixed core.

A rod bow penalty was not required for DNB and LHR calculations.

The 14x14 HTP design allows power operation at a radial peaking limit of 1.65. The T-H design criteria are satisfied for the EPU. The anticipated reduction in margin has been offset by the following major contributors:

- A reduction in the radial peaking limit, and
- An increase in the TS minimum flow rate.

2.8.3.3 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the 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 T-H 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 its current licensing basis with respect to 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. XN-NF-75-21(P)(A), Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady-State and Transient Core Operation, January 1986

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel, January 2005.

4. EMF-1961(P)(A), Revision 0, Statistical/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

5. XN-NF-78-44(NP)(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, October 1983.

6. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

7. IN-1412, TID-4500, A Correlation of Rod Bundle Critical Heat Flux for Water in the Pressure Range 150 to 725 psia, Idaho Nuclear Corporation, July 1970.

8. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 71 to Facility Operating License No. DPR-23 for Carolina Power and Light's H. B. Robinson Steam Electric Plant Unit No. 2, Docket No. 50-261.

9. XN-75-32(P)(A), Supplements 1, 2, 3, and 4, Computational Procedure for Evaluating Fuel Rod Bowing, February 1983.

10. XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model, Exxon Nuclear Company, March 1984.

11. ANF-81-58(P)(A), Revision 2 and Supplements 3 and 4, RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model, Advanced Nuclear Fuels, June 1990.

Table 2.8.3-1
Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	Current Value	EPU Value
Reactor core heat output, MWt	2700	3020
Reactor core heat output, 10^6 BTU/hr	9215	10,307
Heat generated in fuel, %	97.5	97.5
Pressurizer/core pressure, psia	2250	2250
Nominal vessel/core inlet temperature, °F	548	551
RCS minimum flow rate (including bypass), gpm	365,000	375,000
RCS minimum flow rate (including bypass), 10^6 lb_m/hr	137.5	140.76
Core bypass flow, %	3.9	4.2
Core flow area, ft^2	53.15	53.15
Core inlet mass velocity (excluding bypass, based on TS minimum flow rate), 10^6 $lb_m/hr\text{-}ft^2$	2.49	2.54
Pressure drop across core, psi	27.7	29.0
Core average heat flux, BTU/hr-ft^2	183,843	206,277.8
Total heat transfer surface area, ft^2	50,116.5	50,116.5
Average linear power, kW/ft	6.14	6.96
Enthalpy rise hot channel factor (radial peaking)	1.7	1.67

Table 2.8.3-2
Limiting Parameter Direction

Parameter	Limiting Direction for DNB
Reactor core heat output (MWt)	maximum
Heat generated in fuel (%)	maximum
Nominal vessel/core inlet temperature (°F)	maximum
Fr, enthalpy rise hot channel factor	maximum
Pressurizer/core pressure (psia)	minimum
RCS flow(1) (gpm)	minimum
1. The limiting (minimum) value of the RCS flow is the TS minimum flow.	

Table 2.8.3-3
System Related Uncertainties

Parameter	Uncertainty
Reactor Thermal Power	±0.3% (at 100% RTP)
RCS Flow	±15,000 gpm
RCS Pressure	±40.0 psi
Core Inlet Temperature	±3.0°F

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 1 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). FPL's review covered the functional performance of the CEDS to confirm that the system can affect 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:

- 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The St. Lucie Unit 1 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. Local missile barriers are 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.

Refer to UFSAR Sections 3.5, 3.6, 3.7.5 and 3.11 for details.

- 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 acceptable fuel design limits. Analysis of possible reactivity control malfunctions is given in UFSAR Sections 15.2.1 and 15.2.2. 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 a 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.

Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions (refer to UFSAR Section 9.3.4 for details).

- 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 9.3.4 and 4.3. Combined use of CEAs and soluble boron 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 only one group is withdrawn at a time, and that 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 7.1.1.

The RCPB described in UFSAR Chapter 5 and the reactor internals described in UFSAR Chapter 4 are designed to appropriate codes delineated in the response to Criterion 14. The RCPB and internals can 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-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 ANS-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.

Other UFSAR and Technical Specification (TS) sections that address the design features and functions of the Control Rod Drive System include:

- UFSAR Section 4.2.3.1 which provides a general description of the mechanical design and operation of the CEDM.
- UFSAR Section 4.2.3.2 which provides a general description of the mechanical and nuclear design of the CEA.
- UFSAR Section 7.2 which describes the reactor trip system interface with the control rod drive system.
- UFSAR Sections 7.5.1.3 and 7.5.2.3, which describes the operation of the pulse counting and reed switch position transmitter based rod position indication systems.
- UFSAR Section 7.7.1.1.2 which describes the design and operation of the CEA Drive System including the control system interlocks.
- UFSAR Section 9.4.8.3 which describes the design and design requirements of the CEDM cooling system.
- UFSAR Sections 15.2.1 and 15.2.3 describe the transient and accident analyses associated with the malfunctions of the CEDS.
- The Core Operating Limits Report (COLR) describes operating requirements pertaining to CEA misalignment and CEA insertion limits.
- TS 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 the fully inserted position.

The CEDMs are designed to function during and after an operational basis earthquake. The CEDM is capable of tripping or inserting the CEAs after a design basis earthquake. For pipe break accident loads, the CEDMs are designed to maintain the position of the CEAs in the core.

The CEDM is capable of inserting the CEA to the fully inserted position from the fully withdrawn position and transmitting position indication signals for 15 minutes after a postulated LOCA. During the application of the accident loads, ejection of the CEA is prevented in the event of a split of the upper portion of the pressure housing above the operating mechanism, or a major pipe rupture.

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 150°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 St. Lucie Unit 1 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 MWt to 3034 MWt with an associated increase in the reactor vessel best estimate average temperature from 571.4°F to 577.0°F. The total NSSS thermal power level includes the 14 MWt contribution in thermal power from the RCS and is conservative relative to the 2700 MWt and 3020 MWt current and EPU reactor core power levels. The increase in RCS average temperature is expected to increase the best estimate reactor vessel head and CEDM temperature from 594.27°F to 602.9°F. The vessel head and 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 licensed reactor core power from 2700 MWt to 3020 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.
- 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 - Table 1.1-1. These analyses and evaluations are discussed in LR Section 2.2.2.4, Control Rod Drive Mechanism, and 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 total design basis CEDM heat load is 1.65×10^6 BTU/hr and includes heat loads from the CEDMs, control rod cooling shrouds, control rod penetration housings, and the vessel head insulation. As described below, the total CEDM heat load is 1.58×10^6 BTU/hr. This value is bounded by the total design basis heat load. Moreover, as a result of the EPU, there are no physical changes required to the CEDM cooling system.

St. Lucie Unit 1 recently modified the CEDM cooling system as a part of the replacement reactor vessel closure head project. Modification of the CEDM cooling system resulted in the original ductwork riser, torus and two of the shroud outlets being eliminated and replaced with a single ductwork riser that connects directly to the CEDM cooling shroud in a single location utilizing a quick connect clamp-style fitting. The modified ductwork arrangement required no changes to the CEDM cooling system fans or coolers. Further, the original shroud assembly was replaced. As part of the shroud replacement, the shroud orifice plate and chimneys were replaced. Also, four part-length CEDM nozzles were removed. Note that the modified ductwork, from the elevation approximate to the torus associated with the original ductwork to the transition at the elevation of the refueling floor, has a flow area smaller than the modified ductwork. However, because of the more straightforward path (no torus or pressure-robbing tee connections), the pressure losses are lower in the modified ductwork. Also, the chimneys around the nine center CEDMs are increased in size compared to the original design in order to improve cooling and lower overall system pressure loss without decreasing the airflow into the outer chimneys.

The CEDM cooling system ductwork supports consist of embedded cavity wall plates at four locations, brackets and tube steel support arms.

This system is discussed in UFSAR Section 9.4.8.3, 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 150°F with a cooling shroud inlet temperature at the ambient containment air temperature.

As a result of the EPU, as described in Section 2.8.4.1.2.1, the best-estimate reactor vessel closure head temperature increases from 594.27°F to 602.9°F. This temperature increase is bounded by the current analysis for the reactor pressure vessel surface temperature, which is applied at the base of the nozzles and the inside surface of the insulation, is fixed at 650°F. Also, the following parameters are unaffected by the EPU:

- Maximum value for containment ambient temperature of 120°F
- Total design basis CEDM cooling system heat load of 1.65×10^6 BTU/hr

When the reactor vessel closure head was replaced in 2005, the four part-length CEDM nozzles were eliminated, which reduced the CEDM cooling system heat load to 1.58×10^6 BTU/hr. The heat load was further reduced as a result of changes to the insulation and area just above the closure head.

2.8.4.1.3.3 Description of Analyses and Evaluations

A computational fluid dynamics heat transfer analysis was performed as part of the reactor vessel closure head replacement modification to the CEDM cooling system to verify that the system provides sufficient cooling to ensure the CEDM magnetic Jack coils are maintained at a temperature below 350°F and that the cooling shroud exit temperature is maintained at approximately 150°F. This analysis concluded that the maximum CEDM temperature is less than that of the original design and less than the limit of 350°F. Also, this same conclusion was reached for a 10 percent lower inlet flow rate.

This analysis used as its input parameters a total design basis CEDM cooling system heat load of 1.65×10^6 BTU/hr, 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 reactor pressure vessel 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, this analysis remains valid for EPU conditions.

UFSAR Section 4.2.3.1.3 discusses a design requirement associated with the CEDM withstanding a complete loss of cooling air for a period of four hours at normal operating temperature and pressure. Upon restoration of cooling air, the mechanism must be capable of normal operation. This UFSAR section also discusses the test that was performed to verify the CEDM's ability to meet this requirement. The CEDM was tested at reactor operating fluid conditions of 600°F and 2250 psia.

The hot leg temperature under EPU conditions is 602.9°F. Although reactor operating fluid temperature increases 2.9°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 four hour loss of CEDM cooling where convective cooling and normal radiant heat loss would exist.
- 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 CEDM cooling system ductwork supports was performed and it was determined that the results of the current analysis are unaffected by the EPU.

An evaluation of the impact of the EPU on the structural integrity of the CEDM Cooling Ductwork was performed and it was determined that the results of the current analysis are unaffected by the EPU.

2.8.4.1.3.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the control element drive system is within the scope of License Renewal. Operation of the control element drive 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.

2.8.4.1.3.5 Results

EPU has minimal impact upon the temperature in the vicinity of the reed switch position transmitter. The design temperature of the reed switch position transmitter and its sub-components are well in excess of the temperature that the transmitter will experience during EPU operation. The reed switch position transmitter 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 and maintaining the cooling shroud exit temperature at approximately 150°F at the EPU conditions. Therefore, the functional capability of the operating coils are not impacted.

The increased containment heat load on the CEDM cooling system has been evaluated as part of the containment cooling system as discussed in Section 2.7.7, Other Ventilation Systems (Containment) and has been 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 its current licensing basis with respect to the requirements of GDC-4, GDC-23, GDC-25, GDC-26, GDC-27, GDC-28, and GDC-29 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the functional design of the control rod drive system.

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. FPL's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank.

The NRC's acceptance criteria are based on:

- 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);
- 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 that the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in SRP Section 5.2.2 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the overpressure protection during power 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 established for the normal steady state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs. The results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of any AOO.

- 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.

UFSAR Section 5.2.2 states that the RCS is protected against overpressure by ASME Code approved pressurizer safety valves (PSVs), power operated relief valves (PORVs), and the overpressure mitigation system (UFSAR Section 5.2.2.6). Parameters for the PSVs and PORVs are given in UFSAR Section 5.5.3. The pressure relieving capacity of the RCPB is further described in UFSAR Appendix A, Nuclear Steam Supply System Overpressure Protection Report.

NUREG-0737 required utilities to evaluate the functional performance capabilities of pressurized water reactor (PWR) PSVs, PORVs, and block valves. This evaluation was submitted to the NRC and was reviewed and accepted for performance capabilities of pressurizer safety valves and PORVs.

Technical Specification (TS) 3/4.4.3, Reactor Coolant System Safety Valves - 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 4.7-1.

In addition to the licensing bases 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 loss of external load (LOEL) event is the limiting overpressure event for St. Lucie Unit 1, which is analyzed to ensure that the primary and the secondary system pressures remain below the limit of 110 percent of the respective design pressure. The overpressure consequences of this event bound those for other events discussed in LR Section 2.8.5.0, Accident and Transient Analyses.

The LOEL event challenges both the primary and secondary side pressure limits. Details of the analysis performed to support the EPU are provided in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum. The LOEL analyses demonstrated that the primary and secondary pressure limits are met. These analyses also demonstrate compliance with the primary and secondary pressure limits for the cases of inoperable main steam safety valves analyzed with the corresponding power levels.

2.8.4.2.2.2 Description of Analyses and Evaluation

Primary and secondary system pressures must remain below 110 percent of their respective design pressures at all times during the transient. The limiting event with respect to the primary and secondary system overpressurization is the LOEL event. The LOEL analyses documented in LR Section 2.8.5.2.1 demonstrate that primary and secondary pressure limits are met under EPU conditions. The maximum pressure in the primary system was calculated to be less than the limit of 2750 psia (110 percent of design) and the maximum pressure in the secondary system was calculated to be less than the limit of 1100 psia (110 percent of design).

The evaluation of the piping from the PSVs to the quench tank is included in LR Section 2.5.2, Pressurizer Relief Tank. Overpressure protection during low temperature operation is discussed in LR Section 2.8.4.3, Overpressure Protection During Low Temperature Operation.

2.8.4.2.2.3 Evaluation of 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.

2.8.4.2.2.4 Results

The LOEL analyses described in LR Section 2.8.5.2.1 demonstrate that the applicable pressure limits continue to be met at EPU conditions. No changes were needed to the primary or secondary safety valves in order to meet the applicable pressure limits. The analyses support +3% and +2% tolerances for the Bank 1 and Bank 2 MSSV setpoints, respectively, which is an increase compared to the current analysis value of +1%.

2.8.4.2.3 Conclusion

FPL has reviewed the analyses related to the effects of the 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 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 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 power operation.

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.

FPL's 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 1, the pressurizer power operated relief valves (PORVs) are credited for providing low temperature overpressure protection; the relief valves of the shutdown cooling system (referred to as the residual heat removal system in RS-001) are not credited.

The NRC's acceptance criteria are based on:

- 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);
- GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in SRP Section 5.2.2.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC 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 established for the normal steady state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs. The results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of any AOO.

- 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.

UFSAR Section 5.2.2 states that the RCS is protected against overpressure by ASME Code approved safety valves, PORVs, and the overpressure mitigation system (UFSAR Section 5.2.2.6). Parameters for the safety and relief valves are given in UFSAR Section 5.5.3. The pressure relieving capacity of the RCPB is further described in UFSAR Appendix 5A, Nuclear Steam Supply System Overpressure Protection.

The overpressure mitigation system (OMS) provides low temperature overpressure protection (LTOP) for the RCS. The OMS 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 5.4.2, are designed to protect the reactor vessel from potential brittle fracture.

The OMS is designed to mitigate pressure transients by using PORVs, with two temperature dependent, low range pressure setpoints as the pressure relief mechanism. The low range setpoints are energized and de-energized from the main control board through the PORV mode selector switch. Also, means for alarming the various modes of operation have been provided.

TS 3/4.4.13, Power Operated Relief Valves, provides requirements for use of the PORVs for LTOP of the RCS.

The applicable low range pressure setpoint is automatically selected by bistables associated with RCS wide range cold leg temperature transmitters. The measured variable is the reactor coolant pressure obtained from low range pressurizer pressure transmitters. The PORVs open whenever pressurizer pressure is greater than 350 psia with T_{cold} (cold leg temperature) less than 215°F during cooldown or 193°F during heatup/isothermal conditions or pressurizer pressure is greater than 530 psia with T_{cold} between 215–281°F during a cooldown or 193–304°F during heatup/isothermal conditions. When the pressure signal exceeds either setpoint, an alarm informs the operator that the PORVs have received a signal to open from the OMS. The PORVs relieve to the quench tank.

The control switches have three positions: low range, normal range and over-ride. The operator is warned by annunciation to switch over to low range operation on decreasing temperature. The alarm will clear when:

a. PORV control switches are in low range, and

b. PORV block valves are open.

This assures proper alignment of the OMS during shutdown.

During normal RCS heatup the operator is prompted by annunciation to select normal range OMS operation when the temperature increases to the point where low range overpressure protection is no longer needed.

The OMS design includes an anticipatory PORV alarm. This alarm will inform the operator that RCS pressure is approaching the applicable temperature dependent low range OMS PORV actuation setpoint.

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 OMS 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.

As noted in UFSAR Appendix 5B and TS 3/4.4.9, current P-T limit curves and associated LTOP analyses are valid for plant operation to 35 EFPY (approximately 40-year plant life). As part of the EPU, FPL is revising the P-T limit curves and associated LTOP analyses and TS requirements to improve operating margin and to support plant operation to 60-year plant life (end of licensed life).

In addition to the licensing bases described in the UFSAR, the OMS was evaluated for St. Lucie Unit 1 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 OMS are within the scope of License Renewal. Programs used to manage the aging effects associated with the OMS 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

In conjunction with the LTOP system analysis for the EPU, an evaluation was conducted to extend the P-T limits applicability from the current 40-year license to 60-year plant life. The effect of the license extension to 60 years is discussed in LR Section 2.1.2, Pressure-Temperature Limits and Upper-Shelf Energy.

2.8.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

LR Table 2.8.4.3-1 describes the current PORV low range setpoints and applicable RCS temperature range for conditions of heat up and cool down. As a result of the EPU based LTOP analysis, revised applicable temperature ranges for the low range setpoints were selected. This was a result of comparison of the revised EPU based mass addition and energy addition transients to the revised 60-year life P-T limits.

Assumptions

The updated total PORV response time of 0.775 seconds is the basis for LTOP peak transient pressures.

Acceptance Criteria

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 OMS 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 OMS. 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 event 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 TS.

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.

Each analyzed transient assumes pressure relief credit by only a single PORV, even though TS requirements maintain operability of both PORVs. TS 3/4.4.13 currently requires two PORVs and associated low range pressure setpoints for overpressure protection.

The nominal PORV set point is a TS value. The analysis maximum (full open) PORV opening pressure is determined using the nominal opening set point for LTOP, adjusted for actuation loop uncertainty and pressure accumulation during PORV opening delay time.

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 3/4.4.13, in Mode 6, if the RCS is not vented with a vent greater than 1.75 in^2, OMS is required to be operable. This remains valid for the EPU. The PORV orifice area is 1.353 in^2. For any configuration where the PORV is shown in this analysis 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 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 OMS requirements was performed on mass addition and energy addition transients and compared to the revised 60-year plant life P-T limits.

The results of the analysis show that the current PORV setpoint pressures, RCS vent area in Mode 6, cooldown rates, LTOP enable temperature (i.e., the RCS cold leg temperature when OMS is applicable) and the cold leg temperature at which the PORV setpoint transition occurs can be maintained for cooldown. However, for the 60-year plant life P-T limits during cooldown, the TS Section 3.4.13 cold leg temperature at which the PORV setpoint transition occurs will be changed from 215°F to 200°F indicated temperature. This option takes advantage of the margin provided by the new PT limits and is recommended for increased operational simplicity.

Additionally, the EPU LTOP analysis results show that the allowable heatup rates and LTOP enable temperature can be maintained for heatup. However, for the 60-year plant life P-T limits during heatup, the TS Section 3.4.13 cold leg temperature at which the PORV setpoint transition occurs will be changed from 193°F to 200°F indicated temperature. This option is recommended for increased operational simplicity. Also, the cold leg temperature for LTOP enable should be updated to 298.9°F (~ 300°F) to take advantage of the margin provided by the new P-T Limits.

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.

Table 2.8.4.3-1
PORV Setpoint Requirements

Heatup or Cooldown	TS Required PORV Setpoint	TS Required Temperature Range Current	TS Required Temperature Range EPU
Heatup	≤ 350 psia	≤ 193°F	≤ 200°F
Heatup	≤ 530 psia	193°F ≤ T_{cold} ≤ 304°F	200°F < T_{cold} ≤ 300°F
Cooldown	≤ 350 psia	≤ 215°F	≤ 200°F
Cooldown	≤ 530 psia	215°F < T_{cold} ≤ 281°F	200°F < T_{cold} ≤ 300°F

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 (SDC) system at St. Lucie Unit 1, is used to cool down the reactor coolant system (RCS) following shutdown. The SDC system is a low pressure system that takes over the shutdown cooling function when the RCS temperature is reduced. The 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 (SSCs) important to safety 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;
- GDC-34, which specifies requirements for an SDC system.

Specific review criteria are contained in SRP, Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the design relative to the GDC is 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 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 RCS serves as radiation shielding and an effective barrier against internally generated missiles. Local missile barriers are 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 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 Class I seismic pipe which causes a 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.

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 Sections 3.5, 3.6, 3.7.5 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.

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 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.

Residual heat removal capability is provided by the shutdown cooling system (UFSAR Section 9.3.5) for reactor coolant temperatures less than 325°F. For temperatures greater than 325°F, this function is provided by the steam generators and the auxiliary feedwater system. Sufficient redundancy, interconnections, leak detection, and isolation capabilities exist in each of these systems to assure that the residual heat removal function can be accomplished, assuming a single failure. Within appropriate design limits, either system can remove fission product decay heat at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

If the unit is operating at power and there is a turbine trip, there will be a “fast-dead bus” automatic transfer of power to the startup transformers. If offsite power is lost, the electrical equipment required for safe shutdown is loaded on the emergency diesel generators. Refer to UFSAR Section 7.4.

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 RCS through the low pressure injection header.

The SDC system is designed to:

a. reduce the temperature of the reactor coolant from 350°F* to refueling water temperature and maintain this temperature during normal plant shutdown assuming a single active failure.

b. remove post-LOCA decay heat during the recirculation mode of safety injection system operation assuming a single failure.

c. control reactor coolant temperature during the early stages of plant startup.

d. withstand design basis earthquake loads without loss of function.

e. withstand the post-LOCA short and long term environmental and corrosion conditions without loss of function.

* Normal Shutdown Cooling System entry is 325°F

Plant shutdown to refueling conditions is a series of operations that will bring the reactor from a hot standby condition of approximately 2235 psig and 532°F to a shutdown condition of zero psig and 135°F. Mode 6 (refueling) is defined in Technical Specifications (TS), in part as ≤ 140°F, standard plant practice is to cooldown to 135°F prior to entry into Mode 6.

Shutdown cooling is initiated when the RCS conditions drop below the design pressure and temperature of the shutdown cooling equipment. At this time the system is aligned for shutdown cooling. In the shutdown cooling mode, reactor coolant is circulated using one or both of the low pressure safety injection pumps.

The component cooling water (CCW) system is the heat sink to which the reactor coolant residual heat is rejected. Each shutdown heat exchanger receives cooling water to its shell side from a separate CCW system essential header. The shutdown heat exchangers are sized to establish refueling water temperature (135°F) with the design CCW temperature (100°F) 27-1/2 hours after shutdown following an assumed infinite period of reactor operation.

The initial plant cooldown rate is maintained at 75°F per hour or less. The cooldown rate is controlled by adjusting the flow rate through the heat exchangers.

The SDC system is described in greater detail in UFSAR Section 9.3.5.

The operability of the shutdown cooling system is governed by TS Sections 3.4.1.3, 3.4.1.4.1, 3.4.1.4.2, 3.9.8.1, and 3.9.8.2.

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 9.3.5.5 and LR Section 2.8.7.1, Loss of Decay Heat Removal at Mid-loop Operation, for detailed information pertaining to FPL response to the GL 88-17 requirements.

The review requirements associated with “Note 5” as described in Matrix 8 of Section 2.1 of RS-001, specifically the total time necessary to reach the shutdown cooling temperature, are addressed in Section 2.8.4.4.2 below.

In addition to the licensing bases described in the UFSAR, the RHR (SDC) system was evaluated for St. Lucie Unit 1 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 9.3.5. 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:

- conservative SDC heat exchanger input values,
- CCW system supply temperature of 120°F, and
- ANS 1979 decay heat values.

To meet 10 CFR 50 Appendix R Cold Shutdown (Mode 5) criteria, the SDC system, in conjunction with natural circulation cooldown of the RCS, must be able to achieve cold shutdown within 72 hours. 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 increased heat loads will be transferred to the CCW System and ultimately to the Service Water System (SWS), referred to as the Intake Cooling Water (ICW) System. Evaluation of the EPU impact on the performance of the SDC system in conjunction with the CCW and ICW systems with the increased heat loads is addressed in this subsection, 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 cooldown 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. The plant cooldown durations described in this LR Section start from hot standby conditions (Mode 3) and end at either Cold Shutdown (Mode 5) or Refueling (Mode 6) conditions as applicable.

Analyses were performed to demonstrate continued support of TS 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 Evaluation of 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 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.

2.8.4.4.2.5 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. These results are achieved without violating the administrative limit on the maximum cooldown rate of 75°F per hour. Since there are no design criteria for normal plant cooldown times, these increases in the calculated durations, based on design conditions, are acceptable.
- 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 in 63 hours. One train of SDC equipment is then placed in operation and 200°F is achieved in 6 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 TS Action Times with respect to achieving Cold Shutdown (Mode 5 200°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 RCS inventory and therefore, St. Lucie Unit 1 will continue to meet 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.

The EPU has no affect on the ability of the SDC system to comply with GDC-34. The EPU operating conditions have no adverse affect on:

- the design and operating characteristics of the SDC system with respect to its shutdown and long-term cooling function,
- the isolation provisions provided between the high pressure RCS and the lower pressure SDC system and the SDC system overpressure protection features, and
- the design pressures of the RCS and SDC system.

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

2.8.5.0.1 Introduction

This section summarizes the non-loss-of-coolant accident transient analyses and evaluations performed to support the extended power uprate (EPU). The key parameter changes incorporated in the EPU analyses are the following:

<u>Nominal Thermal Power:</u> The nominal thermal power is changed from 2700 MWt to 3020 MWt and is covered in the EPU analyses.o

<u>Power Measurement Uncertainty:</u> The full power measurement uncertainty is changed from 2% to 0.3%, and is applied in the EPU analyses.

<u>Reactor Coolant System (RCS) Flow:</u> The RCS flow is changed from 365,000 gpm to 375,000 gpm and is covered in the applicable analyses. The actual measured flow of greater than 405,000 gpm provides sufficient margin to this revised flow after accounting for the flow measurement uncertainty.

<u>Radial Peaking Factor F_r:</u> The full power value for this parameter is changed from 1.7 to 1.65 to gain analysis margin for the EPU analysis.

<u>MSSV Positive Setpoint As-found Tolerance:</u> This is changed from +1% to +3% for the first bank of safety valves and +2% for the second bank of valves. The revised tolerances are supported by the EPU overpressure analyses. The as-left setpoint tolerance remains at ±1% of the nominal setpoint.

<u>Safety Injection Tank (SIT) Pressure:</u> The SIT pressure in the TS is changed from the current range (200 psig–250 psig) to (230 psig–280 psig). The large break loss-of-coolant (LOCA) analysis supports a bounding SIT pressure range of 200 psig to 280 psig.

<u>SIT and Refueling Water Tank (RWT) Boron Concentration:</u> The SIT and RWT minimum boron concentration is being changed from 1720 ppm to 1900 ppm. The increased boron concentration was input to the safety analyses as the minimum ECCS boron concentration.

<u>MONOBLOCTM Guide Tube Design:</u> The MONOBLOCTM guide tube design has been evaluated to be thermal hydraulically compatible with the current swaged guide tube design with no significant impact on the thermal hydraulic behavior of the core. The EPU analyses, both LOCA and non-LOCA, thus remain applicable for both the guide tube designs. Based on this, the EPU core during the transition cycles does not constitute a mixed core. A 2% mixed core penalty is however applied in the EPU thermal hydraulic analysis.

<u>Steam Generator (SG) Level Low RPS Trip Setpoint:</u> The trip setpoint in the TS is changed from ≥ 20.5% to ≥ 35%. All Chapter 15 analyses, however, conservatively used the current trip setpoint value of ≥ 20.5%

Additionally, the peak linear heat rate (LHR) used in the small break LOCA analysis is 14.7 kW/ft, whereas the other analyses conservatively support the current core operating limits report

(COLR) peak LHR value of 15 kW/ft. The value of peak LHR in the COLR is thus being changed to 14.7 kW/ft for EPU.

2.8.5.0.2 Initial Conditions

Key features of the EPU that were considered in the non-LOCA transient analyses were as follows:

- A nuclear steam supply system (NSSS) power level of 3040 MWt (includes a nominal power level of 3020 MWt plus a conservative RCP heat of 20 MWt);
- AREVA NP's CE 14x14 fuel design;
- A nominal, full power cold leg temperature range of 535°F to 551°F;
- A nominal hot zero power cold leg temperature of 532°F;
- A reactor coolant system minimum flow rate of 375,000 gpm;
- A maximum steam generator tube plugging (SGTP) of 10% ± 2%;
- A nominal operating pressurizer pressure of 2250 psia; and
- A maximum core bypass flow of 4.2%.

Biases were applied to key parameters according to the approved methodology (Reference 1). For the transient analyses, uncertainties were deterministically applied. Thus, steady-state measurement and instrumentation errors were taken into account in an additive fashion to ensure a conservative analysis. For statistical departure from nucleate boiling (DNB) calculations, uncertainties were statistically treated. The system related uncertainties bounded by the safety analyses are:

- Power measurement uncertainty versus reactor power is shown in LR Figure 2.8.5.0-1;
- RCS pressure measurement uncertainty of ± 40 psi;
- Core Inlet temperature measurement uncertainty of ± 3°F; and
- RCS flow rate measurement uncertainty of 15,000 gpm.

LR Table 2.8.5.0-1 shows the assumed key setpoints and capacities. Only safety grade equipment was credited to mitigate an event. Control grade equipment was modeled in such a way that it does not mitigate the effects of an event. For example, the pressurizer power operated relief valves (PORVs) and pressurizer spray system were assumed operable while the pressurizer heaters were assumed inoperable for departure from nucleate boiling ratio (DNBR) transient events where suppressing primary side pressure is conservative. On the other hand, for events that challenge overpressure limits, the pressurizer PORVs and pressurizer spray system were assumed inoperable so as to maximize the pressure response. LR Table 2.8.5.0-12 provides a summary of the initial conditions assumed for each event.

2.8.5.0.3 RPS and ESF Functions

LR Tables 2.8.5.0-2 and 2.8.5.0-3 list the reactor protection system (RPS) and engineered safety feature (ESF) functions credited in the transient analyses, respectively. Uncertainties and response times associated with each of these functions are also given in LR Tables 2.8.5.0-2 and 2.8.5.0-3. The setpoints and response times modeled in the transient analyses were conservatively applied to provide bounding simulations of the plant response. To the extent that the RPS and ESF system are credited in the accident analyses, the setpoints have been verified to adequately protect the plant for EPU operation. There are no changes to the current Technical Specifications (TS) specified for RPS and ESF setpoints except for SG low level.

2.8.5.0.4 Fuel Mechanical Design

The AREVA NP CE 14x14 fuel design was modeled incorporating high thermal performance (HTP) grid spacers, a high mechanical performance (HMP) lower spacer grid and a FUELGUARD™ lower tie plate. The fuel rod cladding material and the cladding for the guide tubes and instrument tube is Zircaloy-4. The key fuel design parameters are summarized in LR Table 2.8.5.0-4.

2.8.5.0.5 Peaking Factors

The power distribution limits for the EPU are shown in LR Table 2.8.5.0-5. For non-LOCA events, a radial peaking factor (F_r) of 1.65 and a peak LHR of 15 kW/ft were modeled. F_r is important for transients that are analyzed to assess DNB concerns. For “fast” events that challenge fuel centerline melt (FCM) (e.g., uncontrolled CEA withdrawal from HZP and CEA ejection), event-specific hot spot power factors were used to calculate fuel centerline temperatures. For events that evolve relatively slowly, the TS radial peaking factor, a conservative axial peaking factor and an event-specific augmentation factor (if required) were combined to determine the challenge to the LHR corresponding to fuel centerline melt.

2.8.5.0.6 Reactivity Coefficients

Transient response of the reactor core is dependent on reactivity feedback effects, in particular the moderator and Doppler feedback. Depending on the event-specific characteristics, e.g., RCS heatup or cooldown, conservatism dictates the use of either maximum or minimum reactivity coefficient values. Justification for the use of the reactivity coefficient values was treated on an event-specific basis. LR Table 2.8.5.0-6 presents the key core kinetics parameters and reactivity feedback coefficients supported by the transient analyses. The current TS limits on moderator temperature coefficients were supported. The Doppler reactivity coefficients were biased according to the approved Reference 1 methodology with additional conservatism to bound expected cycle-to-cycle changes. The continued applicability of the transient analyses is verified for each fuel reload.

2.8.5.0.7 CEA Insertion Characteristics

A time delay of 0.5 second was assumed after the trip breakers open until the CEAs start to insert into the core to account for the time required for the magnetic flux of the CEA holding coils to decay sufficiently to release the CEAs. Including this delay, the time to 90% insertion used in the transient analyses was 3.1 seconds, as shown in LR Figure 2.8.5.0-2.

For events initiated from HFP conditions, a minimum HFP scram worth was used with the most reactive CEA fully withdrawn. For events initiated from HZP conditions, the scram worth was set to the TS minimum shutdown margin requirement (i.e., 3600 pcm). The shutdown margin requirements are verified for each reload cycle.

2.8.5.0.8 Classification of Events

The events are presented in UFSAR Chapter 15. Each event is categorized with respect to its potential consequences. The events fall into two principal classifications: anticipated operational occurrences (AOOs) and postulated accidents (PAs). Where applicable, the RPS and/or ESF were assumed to fulfill their function, as needed, to mitigate the consequences of a given event. The classification for St. Lucie Unit 1 is described below.

<u>Anticipated Operational Occurrences</u>

- AOOs 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.

<u>Postulated Accidents</u>

- PAs include those 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, but less than allowed regulatory limits.

LR Table 2.8.5.0-7 summarizes the event classifications and the respective acceptance criteria. LR Table 2.8.5.0-8 lists each event and its associated classification.

2.8.5.0.9 Events Evaluated or Analyzed

A summary of the non-LOCA event disposition is given in LR Table 2.8.5.0-8 which lists each event, indicates whether that event was reanalyzed for the EPU or bounded by another event or analysis. A tabulation of the RPS and ESF function actuated for each event is given in LR Table 2.8.5.0-9. A summary of the transient analyses limits and results is presented in LR Table 2.8.5.0-10.

The operational modes shown in LR Table 2.8.5.0-11 are consistent with the current TS and were considered in establishing the sub-events associated with each event initiator, as applicable.

2.8.5.0.10 Computer Codes

Descriptions of the principal computer codes used in the safety analyses are provided below. LR Table 2.8.5.0-12 lists the computer code used in each of the non-LOCA analyses.

S-RELAP5

The S-RELAP5 code is an AREVA NP modification of the RELAP5/MOD2 code. S-RELAP5 was used for simulation of the transient system response to accidents. Control volumes and junctions are defined which describe the major components in the primary and secondary systems that are important for the event being analyzed. The S-RELAP5 hydrodynamic model is a two-dimensional, transient, two-fluid model for flow of a two-phase steam-water mixture. S-RELAP5 uses a six-equation model for the hydraulic solutions. These equations include two-phase continuity equations, two-phase momentum equations, and two-phase energy equations. The six-equation model also allows both non-homogeneous and non-equilibrium situations encountered in reactor problems to be modeled.

The S-RELAP5 code has previously been approved for application to St. Lucie Unit 1.

RODEX2

RODEX2 (References 6 and 7) was developed to perform calculations for a fuel rod under normal operating conditions. The code incorporates models to describe the thermal-hydraulic condition of the fuel rod in a flow channel; the gas release, swelling, densification and cracking in the pellet; the gap conductance; the radial thermal conduction; the free volume and gas pressure internal to the fuel rod; the fuel and cladding deformations; and the cladding corrosion. RODEX2 has been extensively benchmarked; its predictive capabilities were correlated over a wide range of conditions applicable to light water reactor fuel conditions. For non-LOCA applications, RODEX2 was used to validate the gap conductance used in the analyses and to establish the fuel centerline melt LHR as a function of exposure. A penalty to cover thermal conductivity degradation with burnup was applied as necessary, where applicable.

The RODEX2 code is currently used in the St. Lucie Unit 1 analysis.

XCOBRA-IIIC

The XCOBRA-IIIC code (Reference 8) is a steady-state thermal-hydraulics code that calculates the axial and radial flow and enthalpy distribution within assemblies and sub-channels for non-LOCA events. When used in conjunction with core boundary conditions from the S-RELAP transient analysis and the HTP DNB correlation (Reference 4), XCOBRA-IIIC also calculates the corresponding MDNBR. MDNBR calculations are performed in a two-step process. Calculations are first performed on a core-wide basis to calculate the axially varying flow and enthalpy distribution in the peak powered fuel assembly. Next, these flow and enthalpy boundary conditions are applied to a sub-channel model of the peak powered assembly to determine the local conditions for the calculation of MDNBR.

The XCOBRA-IIIC code is currently used in the St. Lucie Unit 1 analysis.

PRISM

AREVA NP's pressurized-water reactor (PWR) neutronics methodology uses the NRC-approved advanced nodal simulator code system SAV95. SAV95 is built around the assembly spectrum/depletion code system MICBURN-3/CASMO-3 developed by Studsvik Scandpower and the three-dimensional reactor code PRISM. PRISM is a three-dimensional, coarse-mesh reactor simulator using two-group diffusion theory. The simulator code models the reactor core in three-dimensional (X-Y-Z) geometry, and the reactor calculations can be performed in quarter- or full-core geometry. The code calculates the reactor core reactivity, nodal power distribution, pin power distribution, and in-core detector responses and can be used to simulate fuel shuffling, insertion, and discharge. A summary of the key validation results for the SAV95 code system is presented in Reference 9.

The SAV95/PRISM code is currently used in the St. Lucie Unit 1 analysis.

2.8.5.0.11 Analysis Methodology

The approved methodology for evaluating non-LOCA transients is described in Reference 1. For each non-LOCA transient event analysis, the nodalization, chosen parameters, conservative input and sensitivity studies were reviewed for applicability to the EPU in compliance with the safety evaluation report (SER) for non-LOCA topical report (Reference 1).

- The nodalization used for the calculations supporting the EPU was specific to St. Lucie Unit 1 and was consistent with the Reference 1 methodology.
- The parameters and equipment states were chosen to provide a conservative estimate of the challenge to the acceptance criteria. The biasing and assumptions for key input parameters were consistent with or conservative to the approved Reference 1 methodology.
- The S-RELAP5 code assessments in Reference 1 validated the ability of the code to predict the response of the primary and secondary systems to non-LOCA transients and accidents. No additional model sensitivity studies were needed for this application.

The approved methodology for performing DNB calculations using the XCOBRA-IIIC code is described in Reference 2. The SER for the Reference 2 topical report states that the use of XCOBRA-IIIC is limited to the "snapshot" mode. Thus, MDNBR calculations were performed using a steady-state XCOBRA-IIIC model with core boundary conditions at the time of MDNBR from the S-RELAP5 transient analyses.

The Reference 3 topical report describes the method for performing statistical DNB analyses. Two conditions were noted in the SER for the Reference 3 methodology:

- The methodology is approved only for Combustion Engineering (CE) type reactors which use protection systems as described in the Reference 3 topical report.
- The methodology includes a statistical treatment of specific variables in the analysis; therefore if additional variables are treated statistically Siemens Power Corporation (SPC) (now AREVA NP) should re-evaluate the methodology and document the changes in the treatment of the variables. The documentation will be maintained by AREVA NP and will be available for NRC audit.

Both these conditions are met since St. Lucie Unit 1 is a CE reactor, and no additional variables were used in the statistical DNB analysis.

The DNB calculations were performed utilizing the NRC-approved HTP CHF (or DNB) correlation described in the Reference 4 topical report. The fuel design parameters for AREVA NP's CE 14x14 HTP assembly are within the applicable range for the HTP CHF correlation. The EPU operating conditions are within the applicable range of coolant conditions for the HTP CHF correlation.

CEA ejection analysis was performed to verify compliance with overpressure requirements and to determine the amount of fuel failures based on DNB and fuel centerline melt using the approved Reference 1 methodology. The approved methodology for calculating the enthalpy deposition for a CEA ejection accident is given in Reference 5.

The following calculations, related to post-LOCA and dose consequences, used methods based on basic engineering principles:

- Post-LOCA Criticality (LR Section 2.8.5.6.3) – A mass balance was performed to determine the decrease in boron concentration in the core as the pumped fluid in the containment sump became diluted due to retention of boron in the primary system. Conservative assumptions were made to maximize the dilution of the fluid in the containment sump and minimize the soluble boron concentration in the core. The boron concentration in the core at the time of hot leg injection was compared to the critical boron concentration.
- Atmospheric Steam Releases – An energy balance was performed to determine the steam releases to the atmosphere to cool the plant down to 212°F. The energy balance accounted for the heat contained in the primary and secondary fluid, the heat contained in the primary and secondary metal heat structures and decay heat. Steam release data are used in the radiological dose analyses in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

2.8.5.0.12 Operator Actions

Operator actions credited in the event analyses are identified in LR Table 2.8.5.0-13 along with a disposition relative to the current UFSAR analyses. The respective LR sections discussing these events provide additional detail.

2.8.5.0.13 Setpoint Analyses

The setpoint analyses ensure there is sufficient margin for the Limiting Safety System Settings (LSSS) and LCO systems that monitor various reactor system variables designed to protect the specified acceptable fuel design limits (SAFDLs) and other design limits. The results of the setpoint analyses are presented in LR Table 2.8.5.0-14.

The TS LSS settings are designed to scram the reactor if the monitored parameters reach values that are conservatively set to protect the fuel SAFDLs. The LSSS include reactor trips such as thermal margin/low pressure (TM/LP), local power density (LPD) LSSS, variable high power trip (VHPT), low flow trip, and component pressure and water level trips. The analyses discussed in this LR section verified the TM/LP and LPD LSSS trip settings.

The TS LCOs provide requirements for parameters also associated with the LSSS, such as, the DNB LCO and LPD LCO. The DNB LCO is designed to protect the DNB SAFDL. The LPD LCO is more restrictive and is designed to protect against the LOCA linear heat generation rate (LHGR) limit when the in-core detectors are not in service.

A verification of the TS thermal margin limit lines was also performed. The thermal margin limit lines represent steady-state safety limits with respect to hot leg saturation and DNB. The methodology used in the setpoint verification analyses has been approved by the NRC and is described in Reference 3.

The LPD LSSS barn and results are presented in LR Figures 2.8.5.0-3 and 2.8.5.0-4, respectively. The TM/LP trip functions analyzed are presented in LR Figures 2.8.5.0-5 and 2.8.5.0-6. The DNB LCO barn and results of the transient simulations are presented in LR Figures 2.8.5.0-7, 2.8.5.0-8, and 2.8.5.0-9, respectively. The LPD LCO analysis is essentially the same as the LPD LSSS, except the uncertainties. The LPD LCO barn and results are presented in LR Figures 2.8.5.0-10 and 2.8.5.0-11, respectively. The verification of DNB LCO, LPD LCO, TM/LP LSSS and LPD LSSS is redone for each reload to ensure margin to SAFDLs. The thermal margin limit lines are presented in LR Figure 2.8.5.0-12.

The LSSS and LCO functions are unchanged from the current TS/COLR settings, with exception of the LPD LCO barn. The LPD LCO function was revised to provide margin to the LPD LCO barn. The ASI range at 85% power was reduced from the current TS/COLR values [-0.08, +0.08] to [-0.08, +0.05]. An additional breakpoint was added at 78% power on both the negative and positive sides of the barn at -0.08 and +0.05, respectively. The ASI range at the 45% power breakpoints is unchanged from the pre-EPU settings.

2.8.5.0.14 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-1961(P)(A), Revision 0, Statistical Setpoint/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

4. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

5. XN-NF-78-44(NP)(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, October 1983.

6. XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model, Exxon Nuclear Company, March 1984.

7. ANF-81-58(P)(A), Revision 2 Supplements 3 and 4, RODEX2 Fuel Rod Thermal Mechanical Response Evaluation Model, Advanced Nuclear Fuels, June 1990.

8. XN-75-21(P)(A), Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

9. EMF-96-029(P)(A), Volumes 1 and 2, Reactor Analysis System for PWR's, Volume 1 – Methodology Description, Volume 2 – Benchmarking Results, Siemens Power Corporation, January 1997.

10. WCAP-11596-P-A, Qualification of the PHOENIX- P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988 (Westinghouse Proprietary).

Table 2.8.5.0-1
Key Component Setpoints and Capacities

Item	Nominal Setpoint	Setpoint Tolerance	Total Capacity[1]
Pressurizer Safety Valves (3 valves)	2500 psia	+3%/-2.5%	200,000 lbm/hr/valve at 2500 psia + 3% accumulation
Pressurizer PORV (2 valves)	2400 psia		153,000 lbm/hr/valve at 2400 psia
MSSV (8 total valves per SG)			
• Group 1 (4 valves per SG)	1000 psia	± 3%	743,481 lbm/hr/valve
• Group 2 (4 valves per SG)	1040 psia	+ 2%, - 3%	773,242 lbm/hr/valve
Pressurizer Backup Heaters	NA	NA	1400 kW (max.)
Pressurizer Proportional Heaters	NA	NA	350 kW
Steam Dump and Bypass	NA	NA	7.0[2] Mlbm/hr (max)
Steam Generator Blowdown	NA	NA	50 gpm/SG
Charging Flow	NA	NA	40 gpm/pump (nominal) 49 gpm/pump (maximum)
Auxiliary Feedwater (2 motor-driven pumps and 1 steam-driven pump)	NA	NA	296 gpm (min. degraded flow from one motor-driven pump) 600 gpm (nominal flow from steam-driven pump) 750 gpm (max. run-out flow per motor-driven pump) 1450 gpm (max. run-out flow from steam-driven pump)

1. Analyses support the specified or more conservative values.
2. Analyses support the specified value plus 10%.

Table 2.8.5.0-2
RPS Trip Setpoints and Response Times

Trip	Nominal Trip Setpoint	Uncertainty(1)	Harsh Condition Uncertainty(1)	Response Time (sec.)
Power Level – High(2)				
Four Reactor Coolant Pumps Operating	≤ 9.61% above thermal power with a minimum setpoint of 15% RTP and a maximum of ≤ 107.0% RTP	3%(3)	N/A	≤ 0.4(4) (excluding RTD delay time)
Thermal Margin/Low Pressure (TM/LP)(2) (5)	P_{VAR} = f(T_{IN}, Power, ASI) Min. floor = 1887 psia	± 40 psi	± 80 psi	≤ 0.9 (excluding RTD delay time)
Reactor Coolant Flow – Low(2)	≥ 95% of four pump design reactor coolant flow(6)	± 4%	N/A	≤ 1.025
Pressurizer Pressure – High	≤ 2400 psia	± 35 psi(7)	± 80 psi	≤ 0.9
Steam Generator Pressure – Low	≥ 600 psia	± 40 psi (normal) ± 80 psi (high normal)	± 200 psi	≤ 0.9
Steam Generator Water Level – Low(8)	≥ 20.5% NR (each steam generator)	± 5%	± 14%	≤ 0.9
Steam Generator Pressure Difference – High(2)	≤ 135 psid	± 64 psi (normal) ± 80 psi (high normal)	N/A(9)	≤ 0.9
Containment Pressure – High	≤ 3.3 psig	± 0.55 psi (meas. uncert) ± 1.30 psi (trip uncert.)	N/A	≤ 1.4

Table 2.8.5.0-2 (Continued)
RPS Trip Setpoints and Response Times

Trip	Nominal Trip Setpoint	Uncertainty[(1)]	Harsh Condition Uncertainty[(1)]	Response Time (sec.)

1. These are analysis values which bound actual calculated uncertainties.
2. Trip may be bypassed below 1% RTP; bypass is automatically removed when Wide Range Logarithmic Neutron Flux power is > 1% RTP.
3. Uncertainty is 5% at 100% RTP and a maximum of 10% for power levels < 25% RTP, when combined with power measurement uncertainty.
4. Additional delay of 0.7 sec. added for events initiated at power levels less than or equal to 1% RTP.
5. See LR Figures 2.8.5.0-5 and 2.8.5.0-6.
6. Design reactor coolant flow with 4 pumps operating is 375,000 gpm after accounting for measurement uncertainty.
7. Some analyses have conservatively used 40 psi.
8. Conservative analysis assumption.
9. No analyses requiring harsh conditions tripped on Steam Generator Difference – High.

Table 2.8.5.0-3
ESF Actuation Setpoints and Response Times

Actuation	Nominal Actuation Setpoint	Normal Uncertainty[1]	Harsh Condition Uncertainty[1]	Response Time (sec.)
Main Steam Isolation • Steam Generator Pressure – Low	≥ 600 psia	± 40 psi (normal) ± 80 psi (high normal)	± 200 psi	≤ 6.9 (MSIV) ≤ 60 (MFIV)
Auxiliary Feedwater Actuation • Steam Generator Level – Low	≥ 19.0% NR	± 5%	± 14%	≥ 170[2] ≤ 330[3]
Safety Injection • Pressurizer Pressure – Low	≥ 1600 psia	± 40 psi	± 80 psi	≤ 19.5[2] ≤ 30[3]

1. These are analysis values which bound the actual calculated uncertainties.
2. Diesel generator starting time and sequence loading delays not included (offsite power available).
3. Diesel generator starting time and sequence loading delays not included.

Table 2.8.5.0-4
Core and Fuel Design Parameters

Total Number of Fuel Assemblies	217
Fuel Assembly Design Type	CE14x14
Number of Fuel Rods per Assembly	176
Guide Tubes per Assembly	4
Instrument Tubes per Assembly	1
Fuel Rod Pitch, inches	0.580
Fuel Pellet Outside Diameter, inches	0.377
Clad Inside Diameter, inches	0.384
Clad Outside Diameter, inches	0.440
Heated Fuel Length, inches	136.7
Number of Spacers	9

Table 2.8.5.0-5
Core Power Distribution Parameters

F_r limit (without uncertainties)	1.65
F_r measurement uncertainty	6%
Peak LHR limit, including uncertainties (kW/ft)	15
Peak LHR measurement uncertainty	7%
Engineering tolerance	3%

Table 2.8.5.0-6
Reactivity Parameters

Parameter	BOC	EOC
Moderator Temperature Coefficient (TS limits), pcm/°F	+7 (≤ 70% RTP) +2 (> 70% RTP)	-32 (100% RTP)
Doppler Temperature Coefficient, pcm/°F (bounding range)	-0.80	-1.75
Delayed Neutron Fraction	0.006376	0.005268
U-238 Fission-to-Capture Ratio	0.6866	
Fraction of heat generated in the fuel	0.975	

Table 2.8.5.0-7
Event Classifications and Acceptance Criteria

Event Class	Criteria
Anticipated Operational Occurrences	Specified acceptable fuel design limits (SAFDLs)
	• MDNBR ≥ 95/95 limit
	• Peak fuel centerline temperature melt temperature
	Peak system pressure
	• RCS ≤ 2750 psia
	• MSS ≤ 1100 psia
Postulated Accidents	Radiological doses within regulatory limits
	Peak system pressure
	• RCS ≤ 2750 psia or less than the value that will cause stresses to exceed the faulted condition stress limit
	• Main steam system ≤ 1100 psia

Table 2.8.5.0-8
Summary of Event Disposition

RS-001 Section	UFSAR Section	Class	Event Description	Disposition
2.8.5.1.1	15.2.10	AOO	Decrease in Feedwater Temperature	Bounded
2.8.5.1.1	15.2.10	AOO	Increase in Feedwater Flow	Bounded
2.8.5.1.1	15.2.11	AOO	Increase in Steam Flow	Analyze
2.8.5.1.1	15.2.11.3.2	AOO	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Analyze
2.8.5.1.2	15.4.6	PA	Steam System Piping Failures Inside and Outside Containment	Analyze
2.8.5.1.2	15.3.2	PA	Minor Secondary System Pipe Breaks	Bounded
2.8.5.2.1	15.2.7	AOO	Loss of External Load	Analyze
2.8.5.2.1	15.2.7	AOO	Turbine Trip	Bounded
2.8.5.2.1	15.2.7	AOO	Loss of Condenser Vacuum	Bounded
2.8.5.2.1	15.2.7	AOO	Closure of Main Steam Isolation Valves	Bounded
2.8.5.2.1	---	---	Steam Pressure Regulator Failure	Not in current licensing basis
2.8.5.2.2	15.2.9	AOO	Loss of Non-Emergency AC Power to the Station Auxiliaries	Bounded
2.8.5.2.3	15.2.8	AOO	Loss of Normal Feedwater Flow	Analyze
2.8.5.2.4	15.2.8	PA	Feedwater System Pipe Breaks Inside and Outside Containment	Bounded
2.8.5.2.5	15.2.2	AOO	Transients Resulting from the Malfunction of One Steam Generator	Analyze
2.8.5.3.1	15.2.5	AOO	Loss of Forced Reactor Coolant Flow	Analyze
2.8.5.3.2	15.3.4	PA	Reactor Coolant Pump Rotor Seizure	Analyze
2.8.5.4.1	15.2.1	AOO	Uncontrolled Control Rod Withdrawal from a Subcritical or Low Power Startup Condition	Analyze
2.8.5.4.2	15.2.1	AOO	Uncontrolled Control Rod Withdrawal at Power	Analyze
2.8.5.4.3	15.2.3	AOO	Control Rod Misoperation	Analyze

Table 2.8.5.0-8 (Continued)
Summary of Event Disposition

RS-001 Section	UFSAR Section	Class	Event Description	Disposition
2.8.5.4.4	15.2.6-	---	Startup of an Inactive Loop at an Incorrect Temperature	Event precluded by TS
2.8.5.4.5	15.2.4	AOO	CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant	Analyze
2.8.5.4.6	15.4.5	PA	Spectrum of Rod Ejection Accidents	Analyze
2.8.5.5	---	---	Inadvertent Operation of ECCS	Not in current licensing basis
2.8.5.5	---	---	Chemical Volume Control System Malfunction that Increases Reactor Coolant Inventory	Not in current licensing basis
2.8.5.6.1	15.2.12	AOO	Inadvertent Opening of a Pressurizer Pressure Relief Valve	Analyze
2.8.5.6.2	15.4.4	PA	Steam Generator Tube Rupture	Analyze

Table 2.8.5.0-9
Summary of RPS and ESF Functions Actuated

RS-001 Section	UFSAR Section	Event	RPS and ESF Signal(s) Actuated	Analysis Setpoint	Response Time (sec)
2.8.5.1.1	15.2.11	Increase in Steam Flow	VHPT (high setting) RPS trip	112% RTP	0.4
			VHPT (low setting) RPS trip	25% RTP	1.1(1)
2.8.5.1.1	15.2.11.3.2	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Steam Generator Water Level – Low ESF trip (AFW pump start)	24% NR	0
			Pressurizer Pressure – Low ESF trip (HPSI pump start)	1520 psia	19.5
2.8.5.1.2	15.4.6	Steam System Piping Failures Inside and Outside Containment	VHPT (high setting) RPS trip	112% RTP	0.4
			VHPT (low setting) RPS trip	25% RTP	0.4
			Containment Pressure – High RPS trip (Inside containment breaks)	19.3 psia	1.4
			Steam Generator Pressure – Low RPS trip (Outside containment break)	520 psia	0.9
			Steam Generator ΔP – High RPS trip (Outside containment break)	215 psi	0.9
			Pressurizer Pressure – Low ESF trip (HPSI pump start)	1520 psia	19.5
			Steam Generator Pressure – Low ESF trip (MSIS)	400 psia	0.9
2.8.5.2.1	15.2.7	Loss of External Load	Pressurizer Pressure – High RPS trip	2435 psia	0.9
2.8.5.2.3	15.2.8	Loss of Normal Feedwater Flow	Steam Generator Water Level – Low RPS trip	15.5% NR	0.9
			Steam Generator Water Level – Low ESF trip (AFW pump start)	14% NR	330

Table 2.8.5.0-9 (Continued)
Summary of RPS and ESF Functions Actuated

RS-001 Section	UFSAR Section	Event	RPS and ESF Signal(s) Actuated	Analysis Setpoint	Response Time (sec)
2.8.5.2.5	15.2.2	Loss of External Load to One SG	Steam Generator ΔP – High RPS trip (Outside containment break)	215 psi	0.9
			VHPT (high setting) RPS trip	107.49% RTP[1]	0.4
2.8.5.3.1	15.2.5	Loss of Forced Reactor Coolant Flow	Reactor Coolant Flow – Low RPS trip	91%	1.025
2.8.5.3.2	15.3.4	Reactor Coolant Pump Rotor Seizure	Reactor Coolant Flow – Low RPS trip	91%	1.025
2.8.5.4.1	15.2.1	Uncontrolled Control Rod Withdrawal from a Subcritical or Low Power Startup Condition	VHPT (low setting) RPS trip	25% RTP	1.1[2]
2.8.5.4.2	15.2.1	Uncontrolled Control Rod Withdrawal at Power	VHPT (high setting) RPS trip	LR Table 2.8.5.0-2	0.4
			TM/LP RPS trip	LR Table 2.8.5.0-2	0.9
			Pressurizer Pressure – High RPS trip	2440 psia	0.9
2.8.5.4.3	15.2.3	Control Rod Misoperation	RPS trip not actuated	N/A	N/A
2.8.5.4.5	15.2.4	CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant	TM/LP RPS trip	LR Table 2.8.5.0-2	0.9
2.8.5.4.6	15.4.5	Spectrum of Rod Ejection Accidents	VHPT (high setting) RPS trip	112% RTP	0.4
			VHPT (low setting) RPS trip	25% RTP	1.1[1]

Table 2.8.5.0-9 (Continued)
Summary of RPS and ESF Functions Actuated

RS-001 Section	UFSAR Section	Event	RPS and ESF Signal(s) Actuated	Analysis Setpoint	Response Time (sec)
2.8.5.6.1	15.2.12	Inadvertent Opening of a Pressurizer Pressure Relief Valve	TM/LP RPS trip	LR Table 2.8.5.0-2	0.9
2.8.5.6.2	15.4.4	Steam Generator Tube Rupture	TM/LP RPS trip	LR Table 2.8.5.0-2	0.9

1. The analysis discussed in LR Section 2.8.5.2.5 resulted in a near coincidental Steam Generator ΔP and VHPT. The core power response for this event was conservatively modeled such that DNBR was conservatively predicted.
2. Increased delay is used for events initiated from HZP condition.

Table 2.8.5.0-10
Analysis Limits and Results

RS-001 Section	UFSAR Section	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.1.1	15.2.11	Increase in Steam Flow	MDNBR	≥ 1.164	1.385 (HFP)
			Max. LHR, kW/ft	≤ 22.279	18.686 (HFP)
			Max. centerline temperature, °F	≤ 4623 (EOC)	2165 (HZP)
2.8.5.1.1	15.2.11.3.2	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Shutdown Margin, pcm	> 0 @ 30 min.	> 0 @ 30 min.
2.8.5.1.2	15.4.6	Main Steam Line Break (Core response)			
		• Pre-scram	MDNBR (%fuel failure)	≥ 1.164	0.994 (0.46)
			Max. LHR, kW/ft (% fuel failure)	≤ 22.279	21.449 (0)
		• Post-scram, HFP, Offsite Power Available	MDNBR (% fuel failure)	≥ 1.158	2.732 (0)
			Max. LHR, kW/ft (% fuel failure)	≤ 22.279	21.102 (0)
		• Post-scram, HFP, Loss of Offsite Power	MDNBR (% fuel failure)	≥ 1.158	3.290 (0)
			Max. LHR, kW/ft (% fuel failure)	≤ 22.279	7.044 (0)
		• Post-scram, HZP, Offsite Power Available	MDNBR (% fuel failure)	≥ 1.158	2.431 (0)
			Max. LHR, kW/ft (% fuel failure)	Note (1)	23.342 (0.02)
		• Post-scram, HZP, Loss of Offsite Power	MDNBR (% fuel failure)	≥ 1.158	1.282 (0)
			Max. LHR, kW/ft (% fuel failure)	≤ 22.279	12.788 (0)
2.8.5.2.1	15.2.7	Loss of External Load	MDNBR	≥ 1.164	1.942
			Max. RCS pressure, psia	≤ 2750	2708
			Max. MSS pressure, psia	≤ 1100	1,090 (HFP) 1,097 (part-power)
2.8.5.2.3	15.2.8	Loss of Normal Feedwater Flow	Max. pressurizer liquid volume	Less than volume of pressurizer	Less than volume of pressurizer
			Min. RCS subcooling, °F	≥ 0	47.1
2.8.5.2.5	15.2.2	Loss of External Load to One SG	MDNBR	≥ 1.164	1.778
2.8.5.3.1	15.2.5	Loss of Forced Reactor Coolant Flow	MDNBR	≥ 1.164	1.319

Table 2.8.5.0-10 (Continued)
Analysis Limits and Results

RS-001 Section	UFSAR Section	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.3.2	15.3.4	Reactor Coolant Pump Rotor Seizure	MDNBR (% fuel failure)	≥ 1.164	1.211 (0)
2.8.5.4.1	15.2.1	Uncontrolled CEA Withdrawal from a Subcritical or Low Power Startup Condition	MDNBR	≥ 1.164	6.087
			Max. centerline temperature, °F	≤ 4908 (BOC)	2,036
			Max. RCS pressure, psia	≤ 2750	2568
2.8.5.4.2	15.2.1	Uncontrolled CEA Withdrawal at Power			
		• BOC	MDNBR	≥ 1.164	1.427
			Max. LHR, kW/ft	≤ 22.279	17.9
			Max. RCS pressure, psia	≤ 2750	2657
		• EOC	MDNBR	≥ 1.164	1.239
			Max. LHR, kW/ft	≤ 22.279	17.8
2.8.5.4.3	15.2.3	CEA Misoperation/CEA Drop	MDNBR	≥ 1.164	1.566
			Max. LHR, kW/ft	≤ 22.279	20.750
2.8.5.4.5	15.2.4	CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant/Boron Dilution	Min. time to loss of shutdown margin, min.	≥ 30 (Mode 6)	39.56
				≥ 15 (Modes 1-5)	25.46

Table 2.8.5.0-10 (Continued)
Analysis Limits and Results

RS-001 Section	UFSAR Section	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.4.6	15.4.5	CEA Ejection			
		• BOC, HZP	MDNBR (% fuel failure)	≥ 1.164	2.442 (0)
			Max. centerline temperature, °F (% fuel failure)	≤ 4623[(2)]	4038 (0)
			Fuel pellet average enthalpy, cal/gm	≤ 280	21.2
		• EOC, HZP	MDNBR (% fuel failure)	≥ 1.164	2.917 (0)
			Max. centerline temperature, °F (% fuel failure)	≤ 4623 (EOC)	3212 (0)
			Fuel pellet average enthalpy, cal/gm	≤ 280	29.1
		• BOC, HFP	MDNBR (% fuel failure)	≥ 1.164	1.234 (0)
			Max. centerline temperature, °F (% fuel failure)	≤ 4623[(1)]	4607 (0)
			Fuel pellet average enthalpy, cal/gm	≤ 280	166.4
			Max. RCS pressure, psia	≤ 2750	2696
		• EOC, HFP	MDNBR (% fuel failure)	≥ 1.164	1.984 (0)
			Max. centerline temperature, °F (% fuel failure)	≤ 4623 (EOC)	4385 (0)
			Fuel pellet average enthalpy, cal/gm	≤ 280	155.9
2.8.5.6.1	15.2.12	Inadvertent Opening of a Pressurizer Pressure Relief Valve/Depressurization of the RCS	MDNBR	≥ 1.164	1.350
2.8.5.6.2	15.4.4	Radiological Consequences of Steam Generator Tube Failure	Steam releases for radiological analyses	N/A	N/A

1. The FCM limit of 22.279 kW/ft is the calculated limit to preclude fuel centerline melt across all fuel types. In the HZP Post-trip MSLB case, an evaluation was performed on a pin type specific basis to determine the amount of fuel failure predicted for this event.
2. Lower EOC limit conservatively applied to BOC cases.

Table 2.8.5.0-11
Plant Operational Modes

Description (Mode)	Reactivity Condition, K_{eff}	% Rated Thermal Power(1)	Average Coolant Temperature
Power Operation (1)	≥ 0.99	> 5%	≥ 325°F
Startup (2)	≥ 0.99	≤ 5%	≥ 325°F
Hot Standby (3)	< 0.99	0%	≥ 325°F
Hot Shutdown (4)	< 0.99	0%	325°F > T_{avg} > 200°F
Cold Shutdown (5)	< 0.99	0%	≤ 200°F
Refueling (6)(2)	≤ 0.95	0%	≤ 140°F

1. Does not include decay heat.
2. Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

Table 2.8.5.0-12
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Used	DNB Correlation	Statistical DNB Method	Initial Core Power	RCS Flow Rate (gpm)	Core Inlet Temp. (°F)	Pressurizer Pressure (psia)
Increase in Steam Flow	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3% HZP	375,000	551 HZP: 532	2250
Inadvertent Opening of a Steam Generator Relief or Safety Valve	S-RELAP5 RODEX2 PRISM(1)	N/A	N/A	HZP	375,000	HZP: 532	2250
Steam System Piping Failures Inside and Outside Containment	S-RELAP5 RODEX2 XCOBRA-IIIC PRISM	HTP Modified Barnett	No	3020 MWt + 0.3% HZP	375,000	551 HZP: 532	2250
Loss of External Load	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3%	375,000	535 & 551	2250
Loss of Load to One Steam Generator	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3%	375,000	551	2250
Loss of Normal Feedwater Flow	S-RELAP5 RODEX2	N/A	N/A	3020 MWt + 0.3%	375,000	551	2250
Loss of Forced Reactor Coolant Flow	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3%	375,000	551	2250
Reactor Coolant Pump Rotor Seizure	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	Yes	3020 MWt + 0.3%	375,000	551	2250

Table 2.8.5.0-12 (Continued)
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Used	DNB Correlation	Statistical DNB Method	Initial Core Power	RCS Flow Rate (gpm)	Core Inlet Temp. (°F)	Pressurizer Pressure (psia)
Uncontrolled Control Rod Withdrawal from a Subcritical or Low Power Startup Condition	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	HZP	375,000	HZP: 532	2250
Uncontrolled Control Rod Withdrawal at Power	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3% 2941 MWt + 0.5% 2265 MWt + 2.0% 1510 MWt + 5.0% 755 MWt + 8.0%	SAFDL 375,000 RCS Press. 425,922	532 & 551 550.50 546.25 541.50 536.75	SAFDL 2,250 RCS Press. 2185, 2250, 2315
Control Rod Misoperation	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3%	375,000	551	2250
CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant	N/A	N/A	N/A	Analysis bounds Modes 1 to 6			
Spectrum of Rod Ejection Accidents	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3% HZP	375,000	551 HZP: 532	2250
Inadvertent Opening of a Pressurizer Pressure Relief Valve	S-RELAP5 RODEX2 XCOBRA-IIIC	HTP	No	3020 MWt + 0.3%	375,000	551	2250
Steam Generator Tube Rupture	S-RELAP5 RODEX2	N/A	N/A	3020 MWt + 0.3%	375,000	551	2250

1. St. Lucie Unit 1 neutronic methods also include PHOENIX-P/ANC nuclear design system (Reference 10).

Table 2.8.5.0-13
Assumed Operator Actions and Times

Event	Action Time (min.)	Action	Disposition Relative to Current UFSAR Basis
Excess load	On demand	Trip RCPs at SIAS	Unchanged
Inadvertent opening of a MSSV	≤ 30	Terminate AFW	Unchanged
	≤ 30	Begin boration	Unchanged
Main steam line break	≤ 10	Terminate AFW	Unchanged
SGTR	≤ 45	Isolate the affected steam generator	Actions were unchanged. An operator action time up to 45 min. was supported to gain margin to the current UFSAR analysis time of 30 min.
	≤ 45	Open ADV in the unaffected steam generator.	

Table 2.8.5.0-14
Minimum Margin Summary for Setpoint Calculations

Setpoint Analysis	Margin
LPD LCO[1]	1.11% of rated power
LPD LSSS	7.86% of rated power
TM/LP LSSS	485.17 psid
DNB LCO LOCF	11.85% of rated power
DNB LCO CEAD	25.83% of rated power
Note: The setpoints are verified every cycle with setpoint analysis based on cycle specific core design	
1. Applicable only when Incore Monitoring System is unavailable.	

Figure 2.8.5.0-1
Power Measurement Uncertainty vs. Power

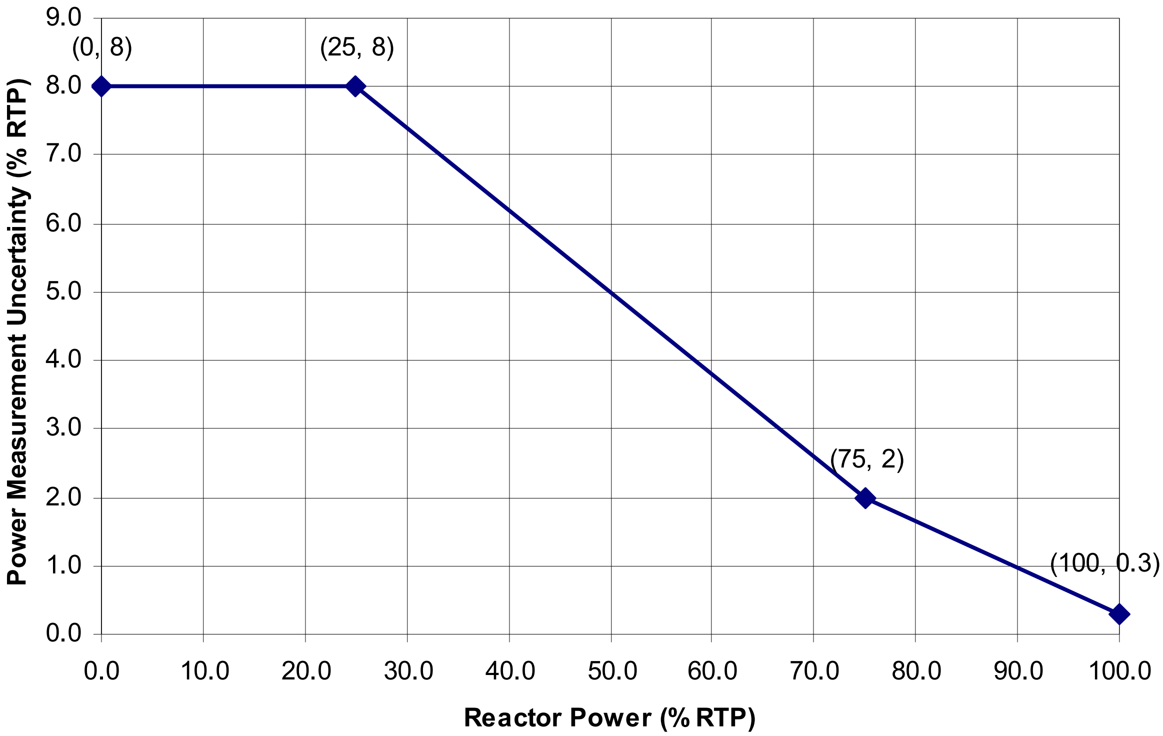


Figure 2.8.5.0-2
CEA Insertion Position vs. Time

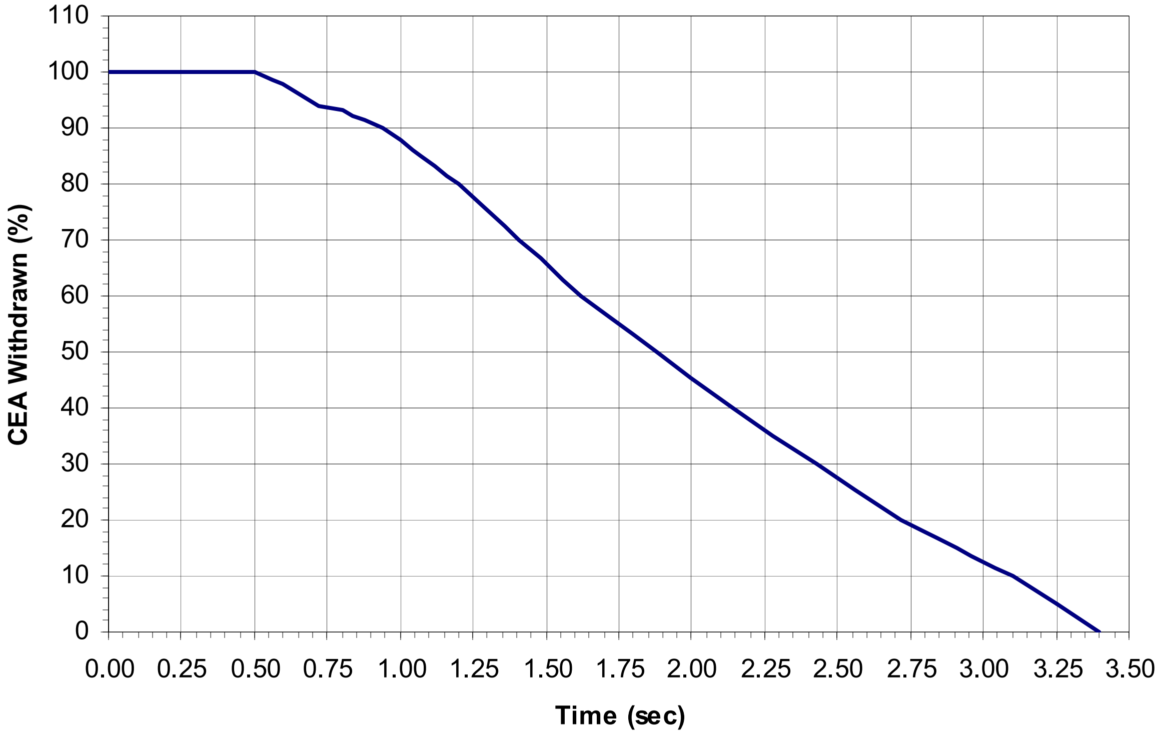


Figure 2.8.5.0-3
LPD – High Trip Setpoint

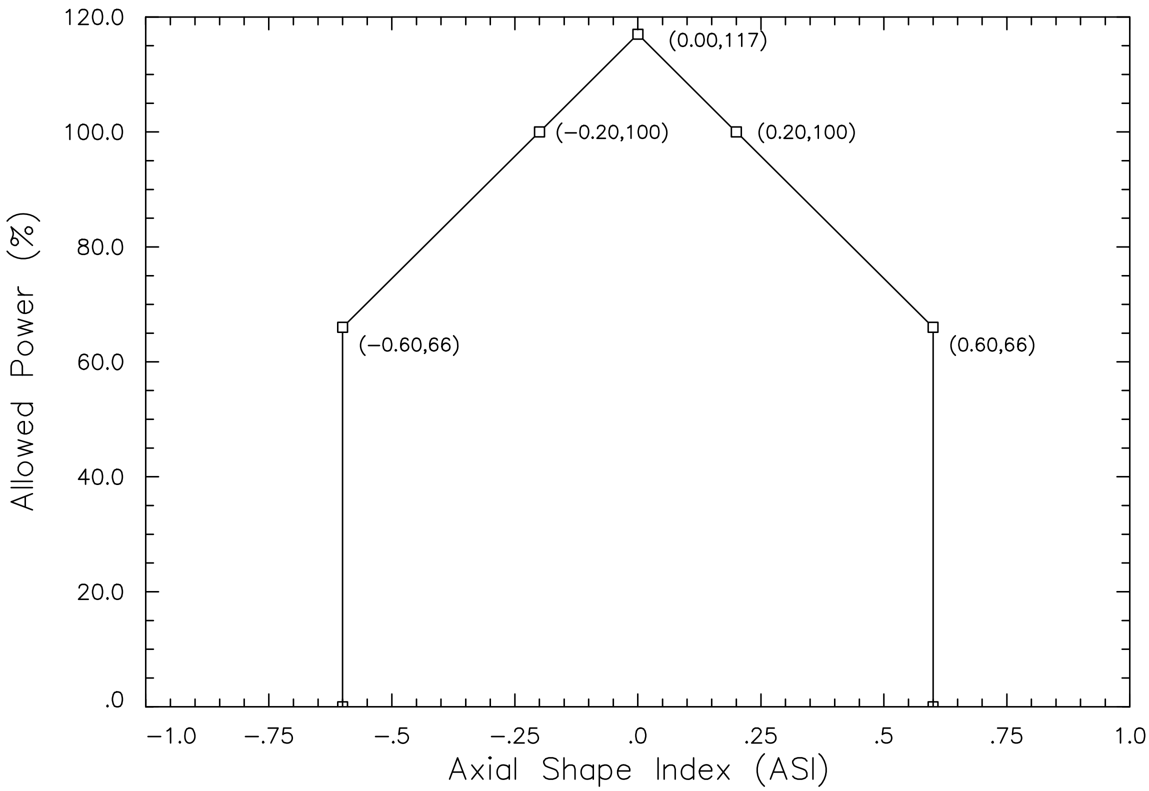


Figure 2.8.5.0-4
LPD LSSS Results

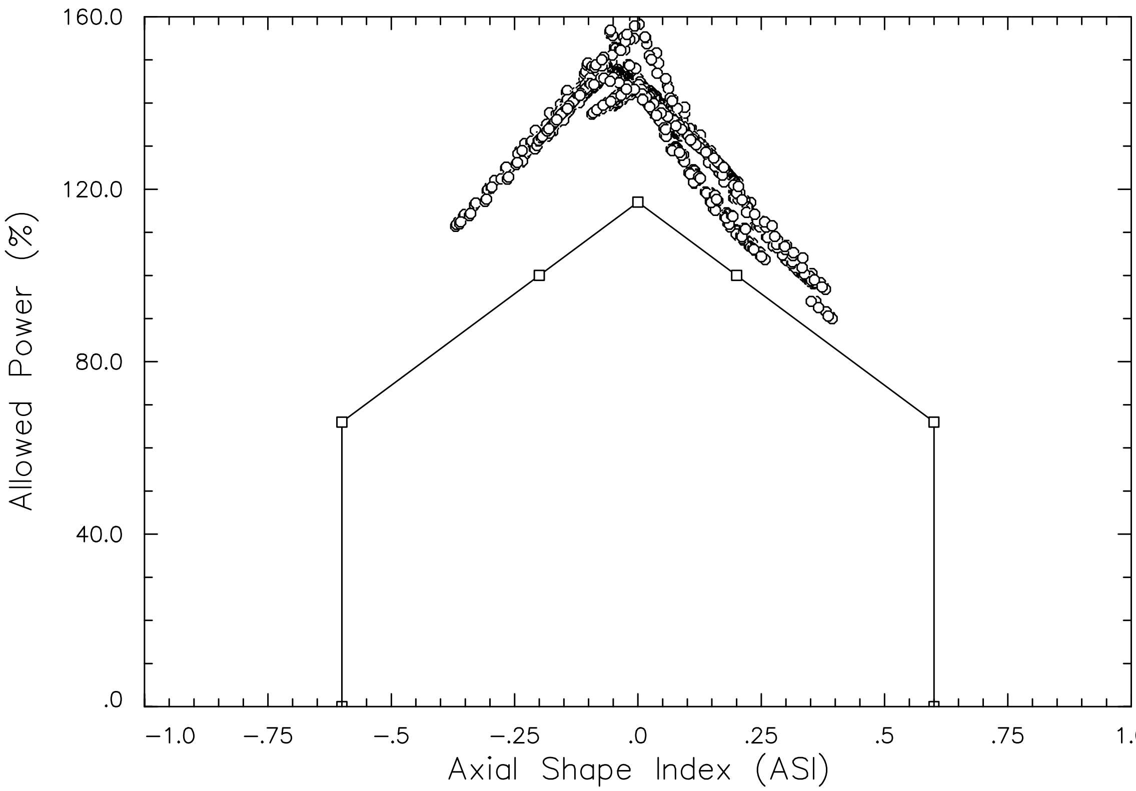


Figure 2.8.5.0-5
TM/LP Trip Setpoint – A1 Function

$$P_{VAR} = 2061 \cdot A1 \cdot QR_1 + 15.85 \cdot T_{IN} - 8950$$

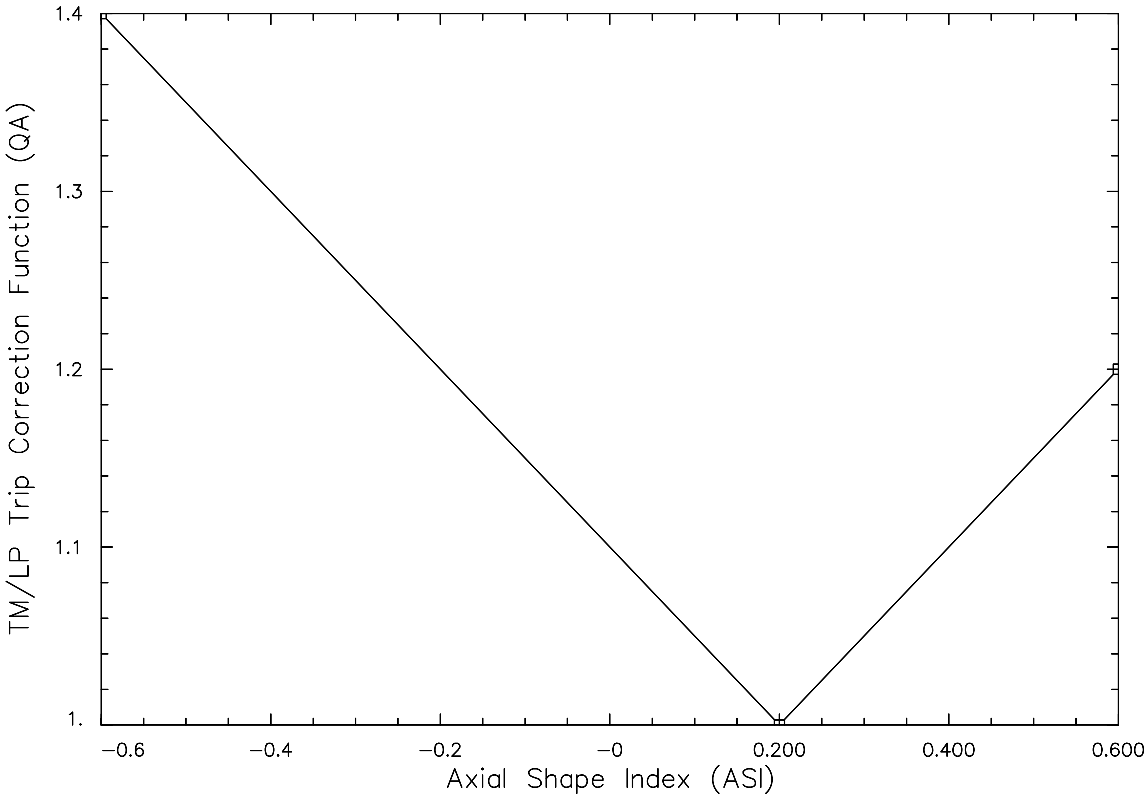


Figure 2.8.5.0-6
TM/LP Trip Setpoint – QR_1 Function

$$P_{VAR} = 2061 \cdot A1 \cdot QR_1 + 15.85 \cdot T_{IN} - 8950$$

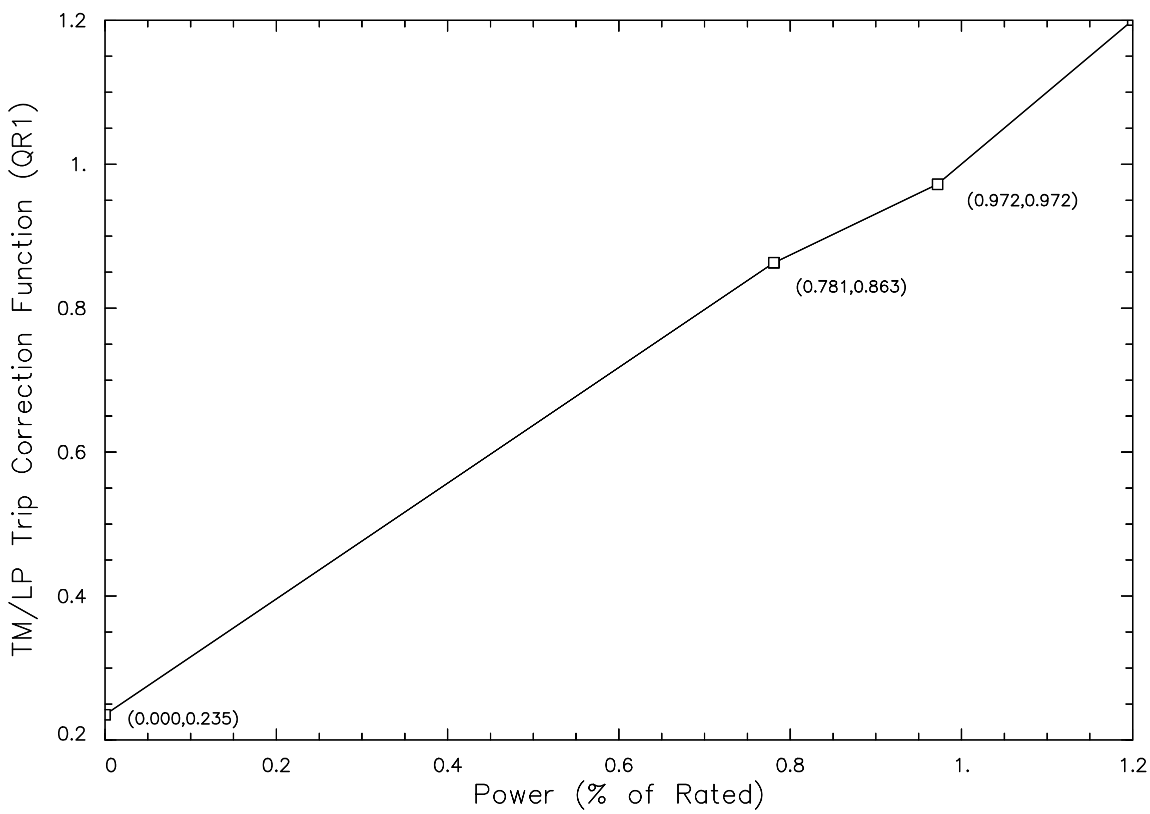


Figure 2.8.5.0-7
ASI Limits for DNB vs. Thermal Power

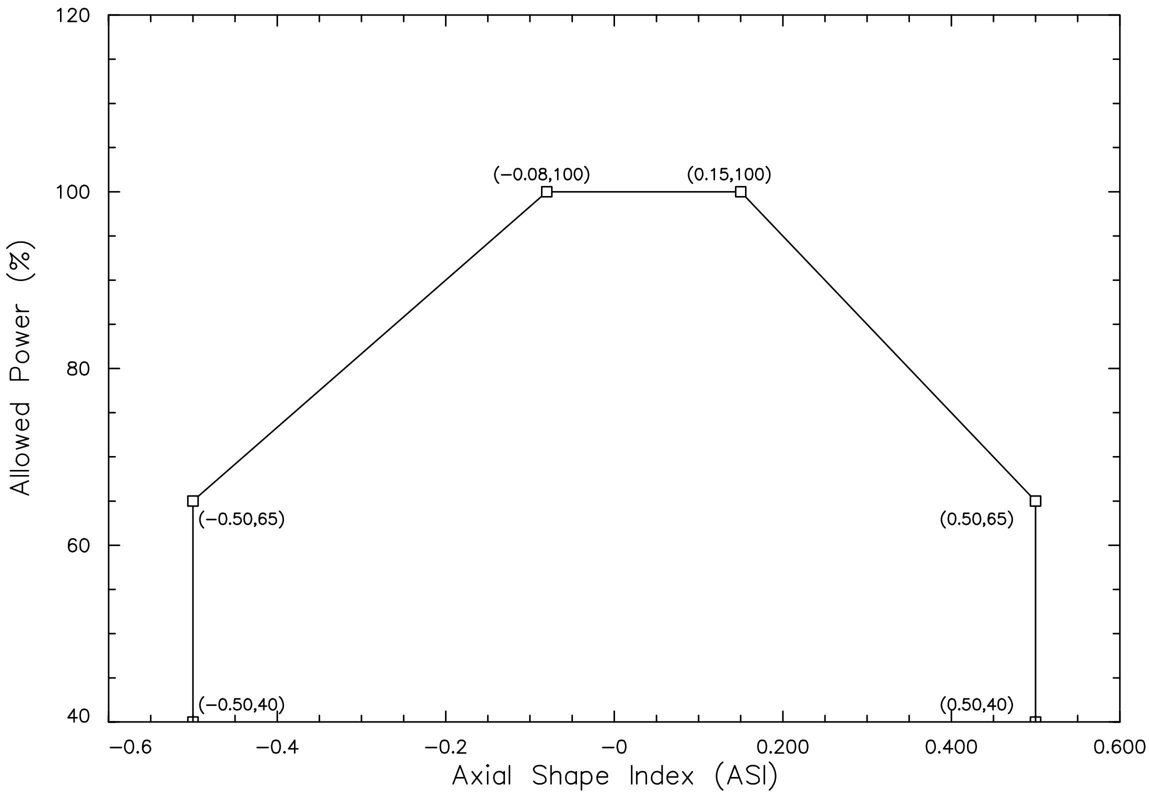


Figure 2.8.5.0-8
DNB LCO CEAD Results

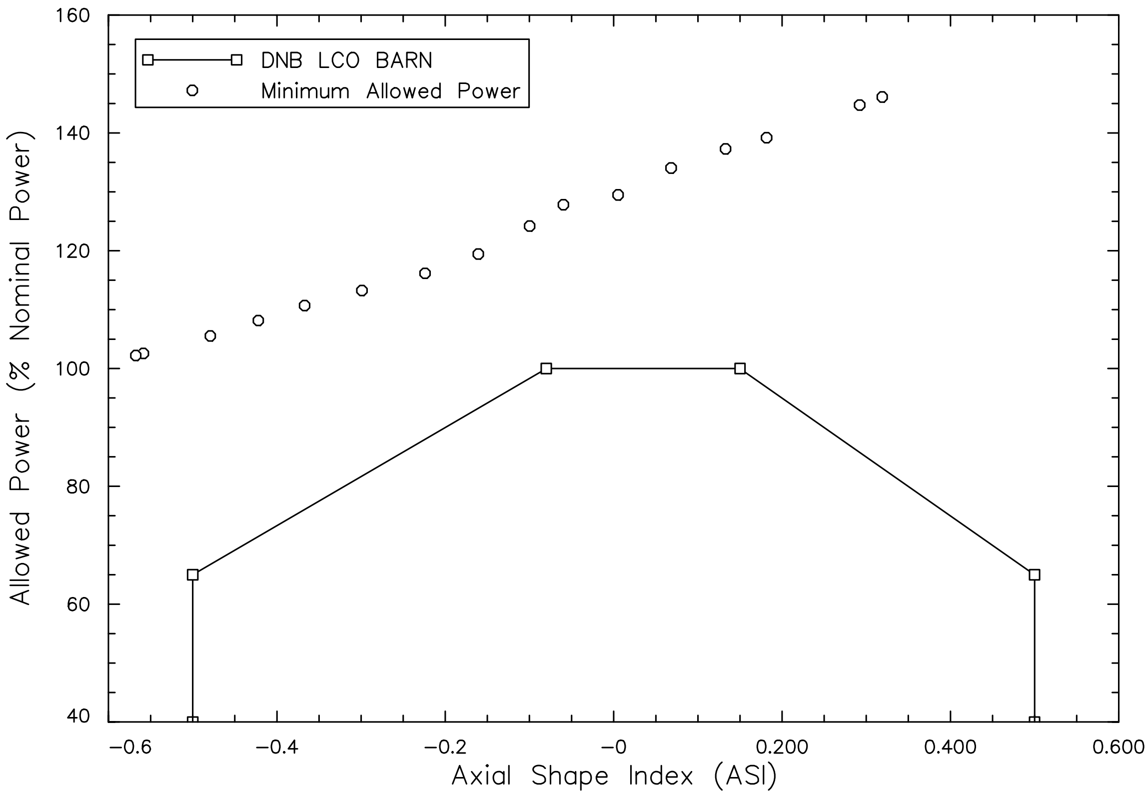


Figure 2.8.5.0-9
DNB LCO LOCF Results

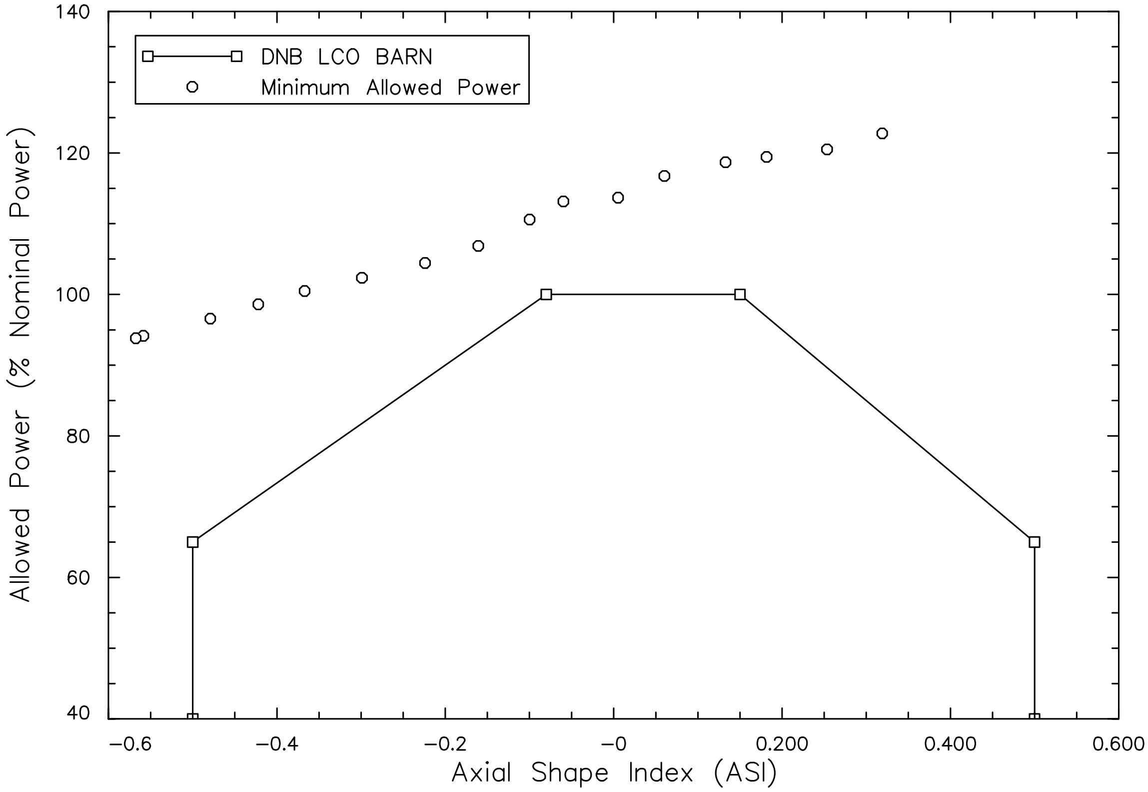


Figure 2.8.5.0-10
ASI Limits for LHR vs. Maximum Allowable Power Level
When Using the Excore Detectors

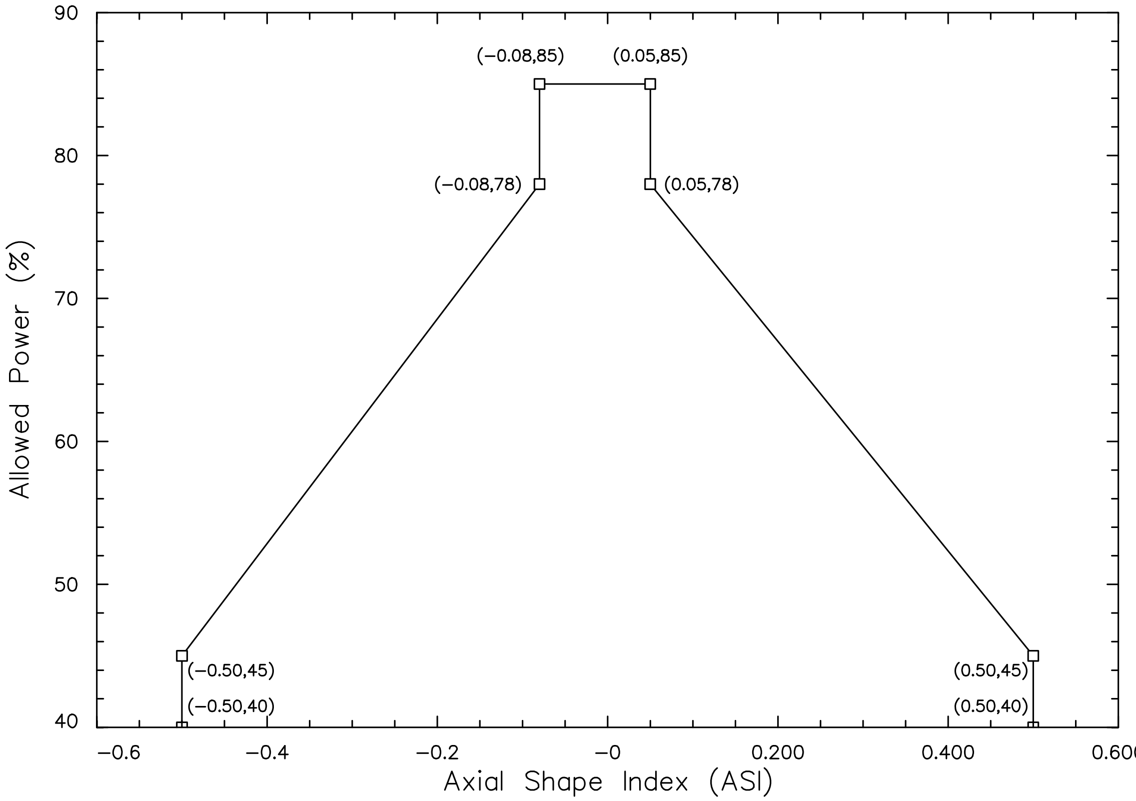


Figure 2.8.5.0-11
LPD LCO Results

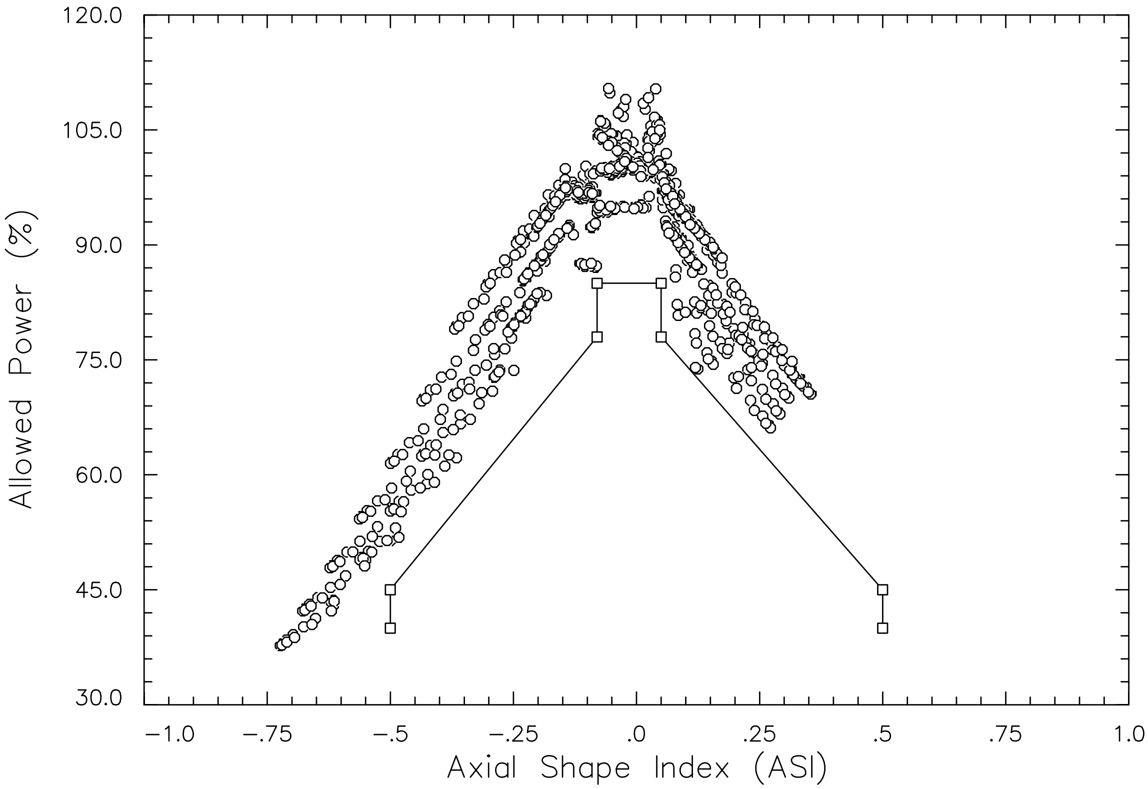
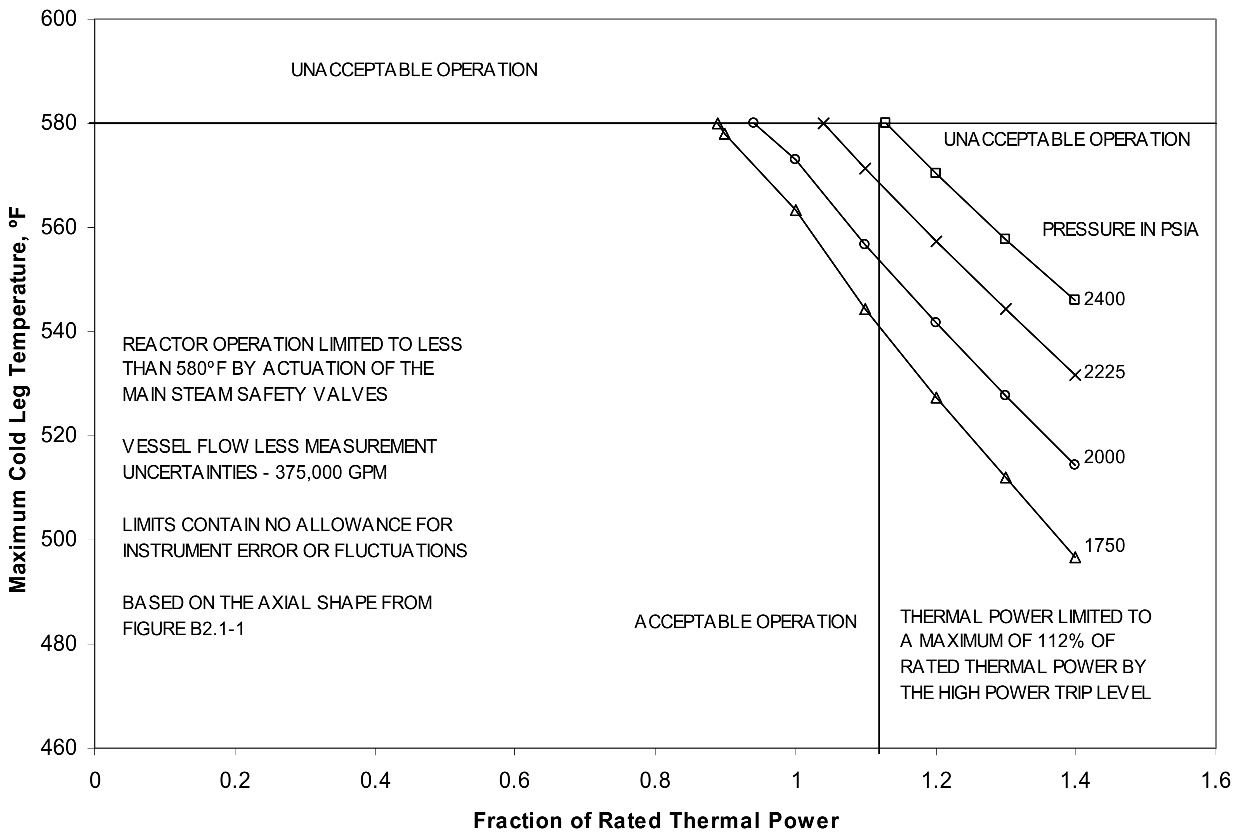


Figure 2.8.5.0-12
Reactor Core Thermal Margin Safety Limit –
Four Reactor Coolant Pumps Operating



2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease In Feedwater Enthalpy, 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.

FPL's 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 (RPS),
- Operator actions, 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-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-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded 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 SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the decrease in feedwater temperature, increase in feedwater flow, increase in steam flow, and inadvertent opening of a steam generator (SG) relief or safety valve transients are:

- 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs. The results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of any AOO.

- 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 protective system 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 acceptable fuel design limits to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features (ESF) actuation system 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 ESF are described in UFSAR Section 7.3.

- 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 controlling reactivity changes to assure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the decrease in feedwater temperature and increase in feedwater flow events is provided in UFSAR Section 15.2.10. Discussion of the increase in steam flow and inadvertent opening of a steam generator relief or safety valve is provided in UFSAR Section 15.2.11.

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 Steam Flow

2.8.5.1.1.2.1.1 Introduction

The increase in steam flow (or excess load increase) event is initiated by a postulated failure or misoperation of the main steam system and results in an increase in steam flow from the SGs. As discussed in UFSAR Section 7.7.2.3.2, the steam dump and bypass system is designed based on the criteria that no single component failure or operator incorrect action can cause the improper opening of more than one dump valve. However, for analysis purposes, the postulated initiating events include the opening of all steam dump and bypass valves or the opening of the turbine control valves due to controller failure.

At hot full power (HFP), the increase in steam flow creates a mismatch between the energy being generated in the reactor core and the energy being removed by the secondary system and results in a cooldown of the primary system. A power increase will occur if the moderator temperature reactivity feedback coefficient is negative. If the power increase is sufficiently large, either overpower or thermal margin limits will be reached with the event being terminated by a reactor trip. If the power increase is less significant, the reactor will stabilize at an elevated power level without reaching a reactor trip and with no violation of any safety limit.

At hot zero power (HZP), the result of the increase in steam flow is a power mismatch between the primary and secondary systems. The immediate response to the additional steam flow demand is a rapid decrease in SG pressure. The SG temperature will also rapidly decrease, as more heat (steam) is being extracted than is being added. Since the reactor is not producing any heat, the secondary side cools down the primary side. The RCS temperatures will decrease and the pressurizer pressure and level will consequently decrease. In the presence of a negative moderator temperature coefficient (MTC) and a negative Doppler reactivity coefficient, positive reactivity insertion will occur in response to the decreasing coolant and fuel temperatures. These feedbacks cause an increase in core power which slows down the decrease in core coolant temperatures. As the core power and fuel temperatures increase, the negative Doppler reactivity coefficient tends to mitigate the rapid increase in power. The core power will increase at an exponential rate until the setpoint on the variable high power trip (VHPT) is reached and initiates a reactor trip. With the decreasing level and pressure, the charging pumps and pressurizer heaters will automatically turn on. Since the pressurizer pressure and level control systems are not safety grade, no credit is allowed for this automatic feature to mitigate the decrease in level and pressure.

2.8.5.1.1.2.1.2 Input Parameters, Assumptions and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions - Two sets of initial conditions were considered. First, the event was assumed to initiate from HFP conditions with a maximum core inlet temperature and TS minimum RCS flow. This set of conditions minimizes the initial margin to departure from nucleate boiling (DNB).

A second set of conditions assumed that the event initiated from a HZP condition. The core inlet temperature was set to the HZP value with TS minimum RCS flow.

- Reactivity Feedback - The reactivity feedback coefficients were biased according to the approved methodology. For the cases initiated from HFP, a range of negative moderator reactivity feedback was analyzed up to an MTC that bounds the most negative TS limit. Negative moderator reactivity feedback leads to higher power levels during the event as a result of the primary system cooldown. Doppler reactivity was biased to minimize the effects of negative feedback from increasing fuel temperatures.

  For HZP initiated cases, the most negative MTC permitted by TS/core operating limits report (COLR) was assumed. Doppler reactivity was biased to minimize the effects of negative feedback from increasing fuel temperatures.

- Reactor Protection System Trips and Delays - The event is primarily protected by the VHPT, which terminates the moderator feedback driven power excursion. The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil delay time.

  The overcooling of the primary system results in decalibration of both the excore nuclear detectors and calculated thermal power signal used as inputs to RPS trips. This results in a delay for the RPS reactor power to reach the VHPT setpoint. In addition, the resistance thermal detector (RTD) delay times for the hot leg and cold leg were conservatively biased to minimize the measured thermal power and further delay the VHPT.

- Feedwater Systems - The main feedwater (MFW) control valve was assumed to increase the feedwater flow in response to the perceived increase in steam flow. For the HFP case, a maximum MFW flow rate of 150% of rated flow was modeled. The auxiliary feedwater (AFW) system was modeled to provide maximum flow at a minimum temperature of 40°F to exacerbate the cooldown of the RCS for the HZP case.

- Steam Dump and Bypass System - A bounding capacity of 7.7 Mlbm/hr was assumed as the initiator of this event. Maximizing the capacity of the steam bypass control system (SBCS) worsens the cooldown of the RCS and the moderator reactivity driven power response.

- Gap Conductance – Gap conductance was set to a conservative end of cycle (EOC) value to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.

- Steam Generator Tube Plugging (SGTP) – No SGTP was assumed so as to maximize the primary-to-secondary side heat transfer which exacerbates the reactivity insertion due to moderator feedback.

- Single Failure – Prior to scram, there is no single failure that will adversely affect the consequences since the systems designed to mitigate this event (namely, the RPS) are redundant. After scram, the worse single failure is the failure of one high pressure safety injection (HPSI) pump to start and deliver boron to the core.

The principally challenged acceptance criterion for this event is:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

This criterion is met by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the 95/95 DNB correlation limit. Additionally, fuel centerline melt is demonstrated to be precluded in the most adverse location in the core.

2.8.5.1.1.2.1.3 Description of Analyses and Evaluation

The current licensing basis calculations in the UFSAR were performed using the ANF-RELAP code (Reference 1) For the EPU, detailed analyses were performed with the approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), an estimated time of minimum departure from nucleate boiling ratio (MDNBR) and peak system pressures. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 3), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 4).

2.8.5.1.1.2.1.4 Evaluation of 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

Increase in Steam Flow (Hot Zero Power)

The sequence of events is given in LR Table 2.8.5.1.1-1 and the results are given in LR Table 2.8.5.1.1-2. Statepoints for the DNB calculations were chosen at and near the time of peak heat flux. The limiting MDNBR was calculated to be bounded by that for the HFP case. The peak centerline temperature during the event was calculated to be less than the fuel melt temperature limit.

The transient response is shown in LR Figures 2.8.5.1.1-1 through 2.8.5.1.1-9. LR Figure 2.8.5.1.1-1 shows the reactor power as a function of time. LR Figure 2.8.5.1.1-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.1.1-3 through 2.8.5.1.1-9 show the pressurizer pressure, the RCS loop temperatures, the total RCS flow rate, the SG pressures, the steam and feedwater flow rates, the reactivity feedback, and the peak fuel centerline temperature, respectively.

Increase in Steam Flow (Hot Full Power)

The sequence of events is given in LR Table 2.8.5.1.1-1 and the results are given in LR Table 2.8.5.1.1-2. Statepoints for the DNB calculations were chosen at and near the time of peak heat flux. The limiting MDNBR was calculated to be above the 95/95 CHF correlation limit. The peak linear heat rate (LHR) was calculated to be less than the fuel centerline melt limit.

The transient response is shown in LR Figures 2.8.5.1.1-10 through 2.8.5.1.1-17. A steam flow of 7.7 Mlbm/hr, which bounds the maximum capacity of the SBCS, was found to most challenge the acceptance criteria. LR Figure 2.8.5.1.1-10 shows the reactor power as a function of time and LR Figure 2.8.5.1.1-11 shows the core power based on rod surface heat flux. LR Figures 2.8.5.1.1-12 through 2.8.5.1.1-17 show the pressurizer pressure, the RCS loop temperatures, the total RCS flow rate, the steam generator pressures, the steam and feedwater flow rates, and the reactivity feedback, respectively.

2.8.5.1.1.2.2 Decrease in Feedwater Temperature

This event is initiated by a reduced feedwater temperature at full power. A decrease in feedwater temperature may be caused by a loss of one of several feedwater heaters or an accidental starting of the AFW system. The sudden reduction in feedwater temperature results in a cooldown of the SG, a temperature and pressure decrease in the RCS, and a higher power with a most negative MTC at EOC. The increase in power and reduction in RCS pressure during the transient cause a decrease in DNB margin, while the decrease in RCS temperature during the transient causes an increase in DNB margin. The overall effect is a decrease in DNB margin and a challenge to the DNB SAFDL. However, the increase in heat removal due to a decrease in feedwater temperature is far less than that for the increase in steam flow event. The operating conditions for the EPU will not change the relative behavior and severity of this event. This event remains bounded by the increase in steam flow event.

2.8.5.1.1.2.3 Increase in Feedwater Flow

An increase in feedwater flow event, initiated at HFP, is caused by the complete opening of a single feedwater control valve, because the two feedwater control valves and their control are independent. This event is addressed in LR Section 2.8.5.2.5, Asymmetric Steam Generator Transient.

2.8.5.1.1.2.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

2.8.5.1.1.2.4.1 Introduction

This event is initiated by the inadvertent opening of an atmospheric dump valve (ADV) or a main steam safety valve (MSSV). The limiting scenario for this event is initiated by the inadvertent opening of an MSSV, since the MSSV flow capacity is greater than an ADV capacity. The purpose of this analysis is to address the potential for a return-to-criticality from a HZP, subcritical condition with all rods in condition (Mode 3).

2.8.5.1.1.2.4.2 Input Parameters, Assumptions and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0 for the input parameter values.

- A HZP initial condition was simulated to maximize the initial SG pressure and inventory, which worsens the erosion of shutdown margin. The CEAs were assumed to be initially inserted.
- EOC conditions worsen the erosion of shutdown margin by maximizing the positive reactivity from moderator feedback and by minimizing the scram worth.
- Credit was not taken for the check valves in the steam lines, thus flow to the affected MSSV is received from both SGs until MSIV closure.
- No loss of offsite power was assumed to maximize the primary-to-secondary heat transfer.
- Loss-of-a-HPSI pump single-failure was assumed. Failure of an MSIV to close was not assumed since closure of either MSIV would stop the backflow from the “unaffected” SG.
- No operator action to mitigate the erosion of shutdown margin prior to 30 minutes. After 30 minutes, the operators are assumed to terminate AFW and begin boration to a cold shutdown condition.
- Gap conductance was set to a conservative EOC value to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.

The acceptance criteria for this event are:

- The pressures in the RCS and main steam system should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

The first criterion is always met for this cooldown event and does not need to be specifically addressed. The second criterion is met if there is no increase in power during the event. This can be demonstrated by assuring that shutdown margin is not lost during the event. This event is also addressed in LR Section 2.8.5.2.5, Asymmetric Steam Generator Transient.

2.8.5.1.1.2.4.3 Description of Analyses and Evaluation

The current licensing basis calculations in the UFSAR were performed using the ANF-RELAP code (Reference 1). For the EPU, detailed analyses were performed with the approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). A core neutronics analysis was performed at the time of peak post-scram reactivity during the transient using power, RCS pressure and RCS temperature boundary conditions from S-RELAP5 for the purpose of evaluating shutdown margin.

2.8.5.1.1.2.4.4 Evaluation of 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.

2.8.5.1.1.2.4.5 Results

The sequence of events is given in LR Table 2.8.5.1.1-3. An analysis of the erosion of shutdown margin was performed for the EPU that demonstrated that the core remains subcritical to at least 30 minutes, at which time the operators are assumed to initiate actions to bring the plant to a safe shutdown condition. The results of this analysis are summarized in LR Table 2.8.5.1.1-4.

The transient response is shown in LR Figures 2.8.5.1.1-18 through 2.8.5.1.1-28. LR Figure 2.8.5.1.1-18 shows the reactor power as a function of time. LR Figures 2.8.5.1.1-19 through 2.8.5.1.1-28 show the steam flow rates, SG inventories, SG liquid levels, feedwater flow rates, SG pressures, cold leg temperatures, pressurizer pressure, pressurizer liquid level, HPSI flow rate, and the reactivity feedback, respectively.

The radiological dose analyses for this event are provided in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

2.8.5.1.1.3 Conclusion

FPL has reviewed the excess heat removal events described above, and concludes that the analyses have adequately accounted for operation of the plant at the proposed EPU 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 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. ANF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. EMF-2310(P)(A) Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.1.1-1
Increase in Steam Flow
Sequence of Events

Case	Event	Time (sec.)
Hot Zero Power	Turbine control valves fully opened AFW reaches full delivery rate	0.0
	VHPT setpoint reached	10.8
	Peak power in transient	10.9
	Reactor scram on VHPT (Reactor scram on VHPT (including trip response delay)	11.9
	CEA insertion begins	12.4
	Maximum clad surface heat flux	13.8
	MDNBR	13.8
	Maximum fuel centerline temperature	14.6
	CEAs fully inserted	15.4
	Main steam isolation setpoint reached	20.8
	HPSI setpoint reached	25.4
	RCP tripped	25.4
	Main steam isolation completed	27.7
Hot Full Power	SBCS system opens to full capacity	0.0
	VHPT setpoint reached	19.4
	Reactor scram on VHPT (including trip response delay)	20.3
	CEA insertion begins	20.8
	Minimum (prior to scram) core inlet temperature reached	20.8
	Peak neutronic power	20.8
	Maximum clad surface heat flux	20.9
	MDNBR	20.9

Table 2.8.5.1.1-2
Increase in Steam Flow
Results

Criterion	HZP	HFP	Limit
MDNBR	Bounded by HFP	1.385	1.164
Peak Centerline Temperature	2165°F	N/A	4623°F
Peak LHR	N/A	18.7 kW/ft	22.3 kW/ft

Table 2.8.5.1.1-3
Inadvertent Opening of a Steam Generator
Relief or Safety Valve
Sequence of Events

Event	Time (sec.)
MSSV failed open with reactor at EOC, HZP, subcritical condition	0.0
RCS pressure reached low-pressure SIAS setpoint	582.6
HPSI pumps available for injection	602.1
RCS pressure reached HPSI pump shutoff head and HPSI delivery began	714
Secondary pressure reached MSIS setpoint	745.4
MSIV were fully closed	752.3
Liquid level of affected SG reaches low-low-level AFAS setpoint and full auxiliary feedwater delivery begins	1047.3
Borated water began to enter the RCS (HPSI lines flushed)	1122.6
Shutdown margin reached minimum value	1595
Liquid level in affected steam generator reached 100% span and AFW termination assumed	1681
Operator assumed to begin boration to cold shutdown condition	1800

Table 2.8.5.1.1-4
Inadvertent Opening of a Steam Generator
Relief or Safety Valve
Results

Criterion	Previous Analysis	EPU Analysis	Limit
Shutdown Margin	> 0 pcm @ 30 min.	> 0 pcm @ 30 min.	> 0 pcm @ 30 min.

Figure 2.8.5.1.1-1
Increase in Steam Flow (HZP)
Reactor Power

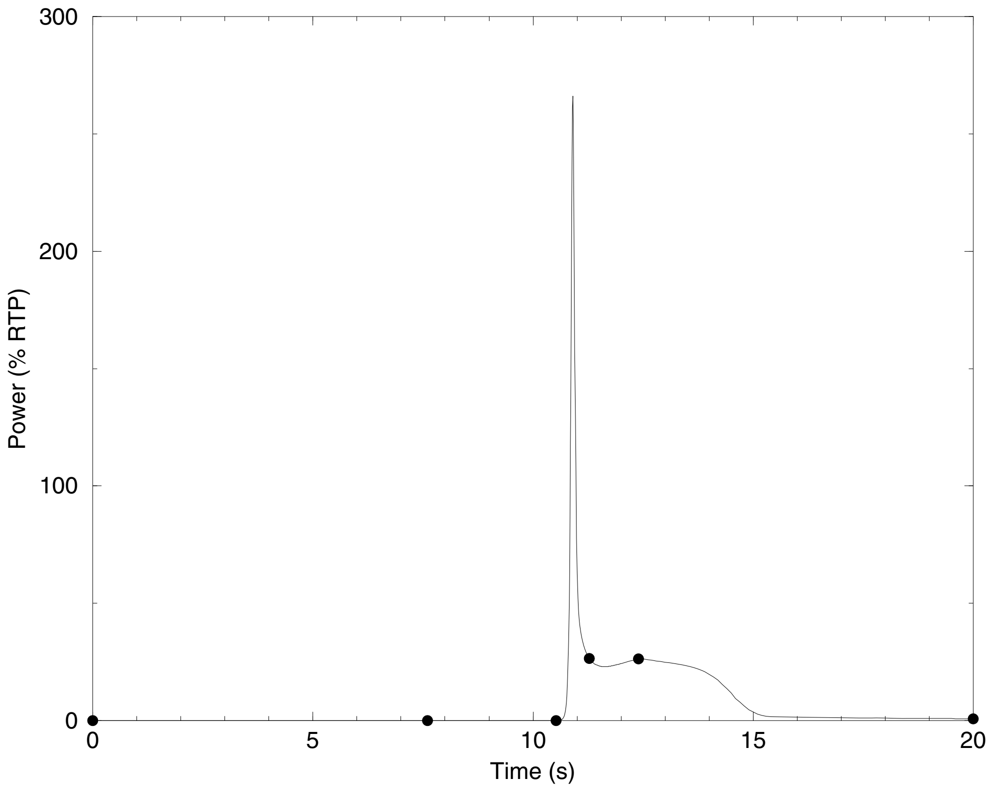


Figure 2.8.5.1.1-2
Increase in Steam Flow (HZP)
Total Core Heat Flux Power

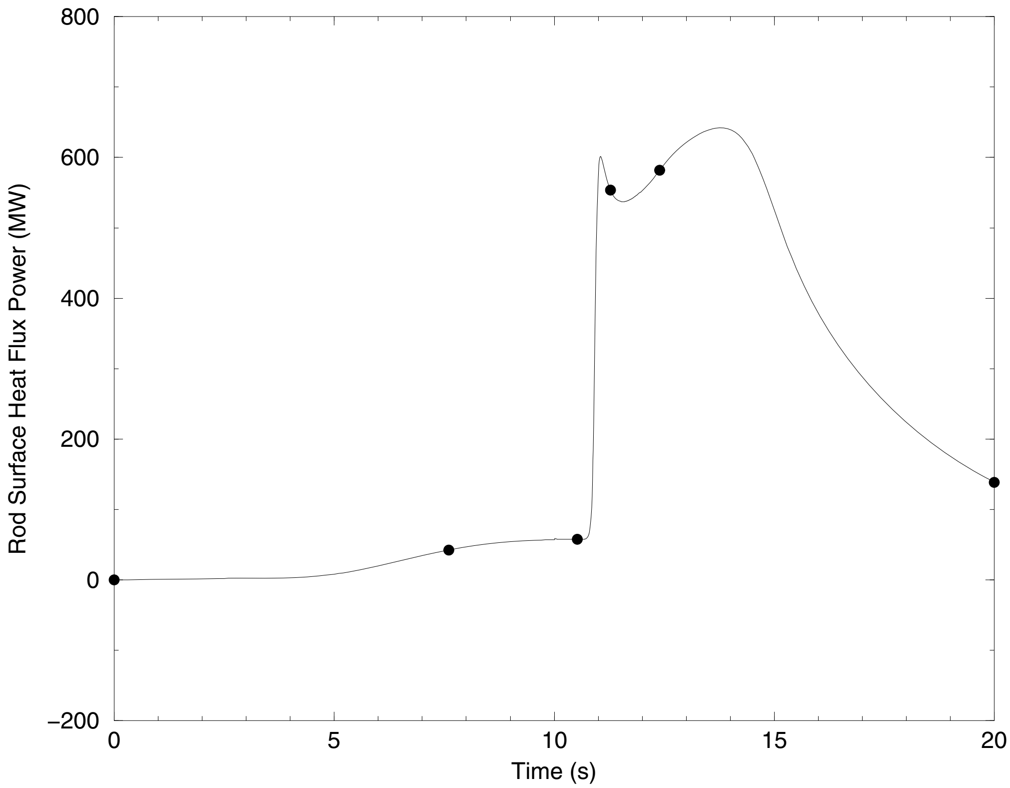


Figure 2.8.5.1.1-3
Increase in Steam Flow (HZP)
Pressurizer Pressure

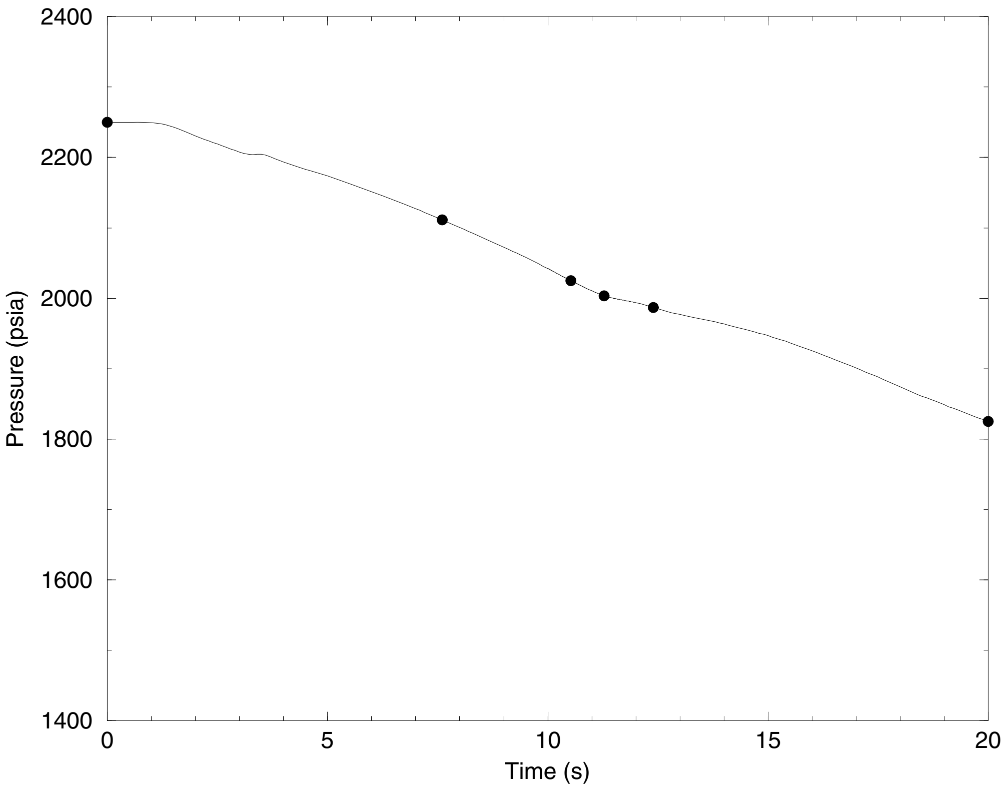


Figure 2.8.5.1.1-4
Increase in Steam Flow (HZP)
RCS Loop Temperatures

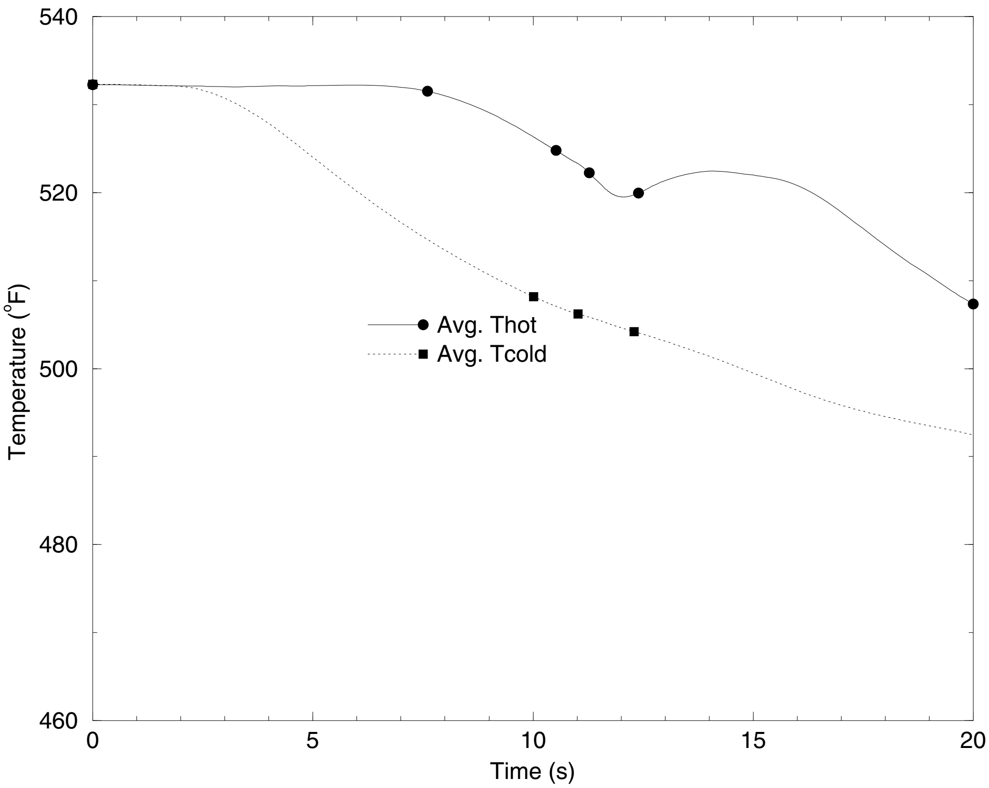


Figure 2.8.5.1.1-5
Increase in Steam Flow (HZP)
RCS Total Loop Flow Rate

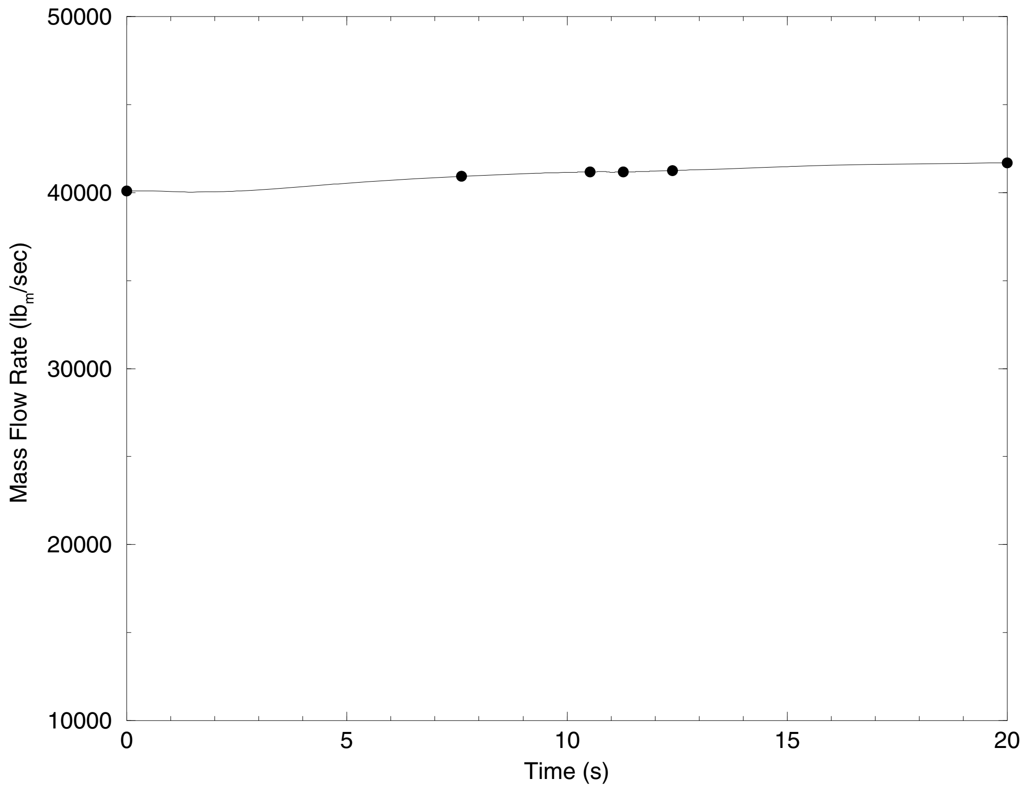


Figure 2.8.5.1.1-6
Increase in Steam Flow (HZP)
Steam Generator Pressures

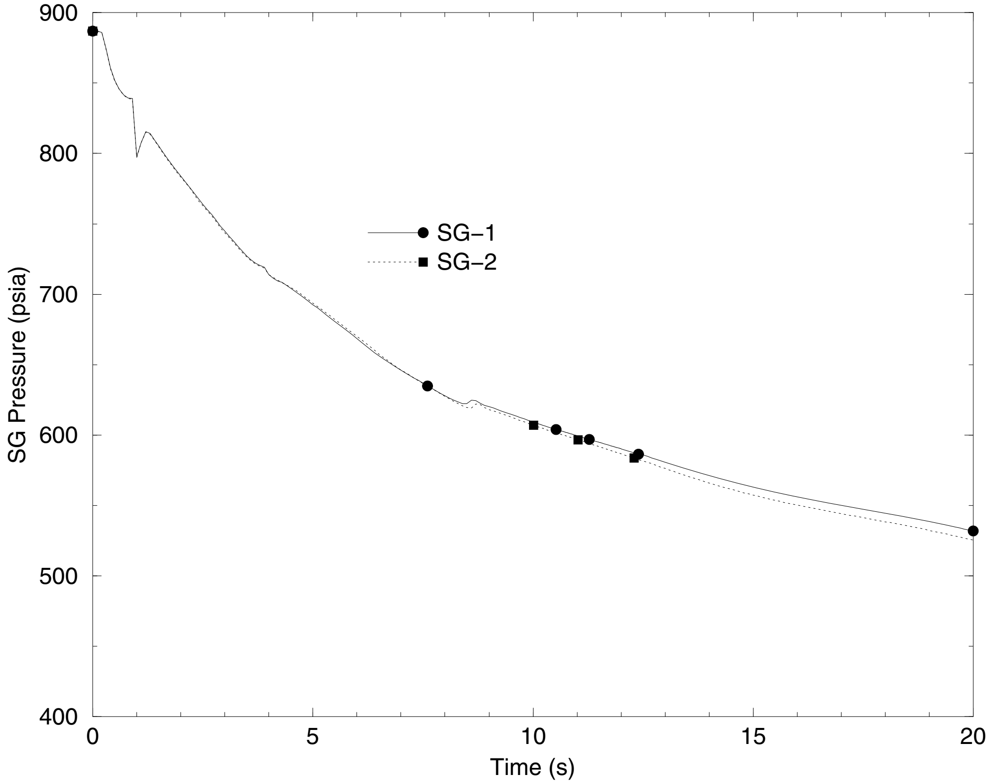


Figure 2.8.5.1.1-7
Increase in Steam Flow (HZP)
Steam and Feedwater Flow Rate

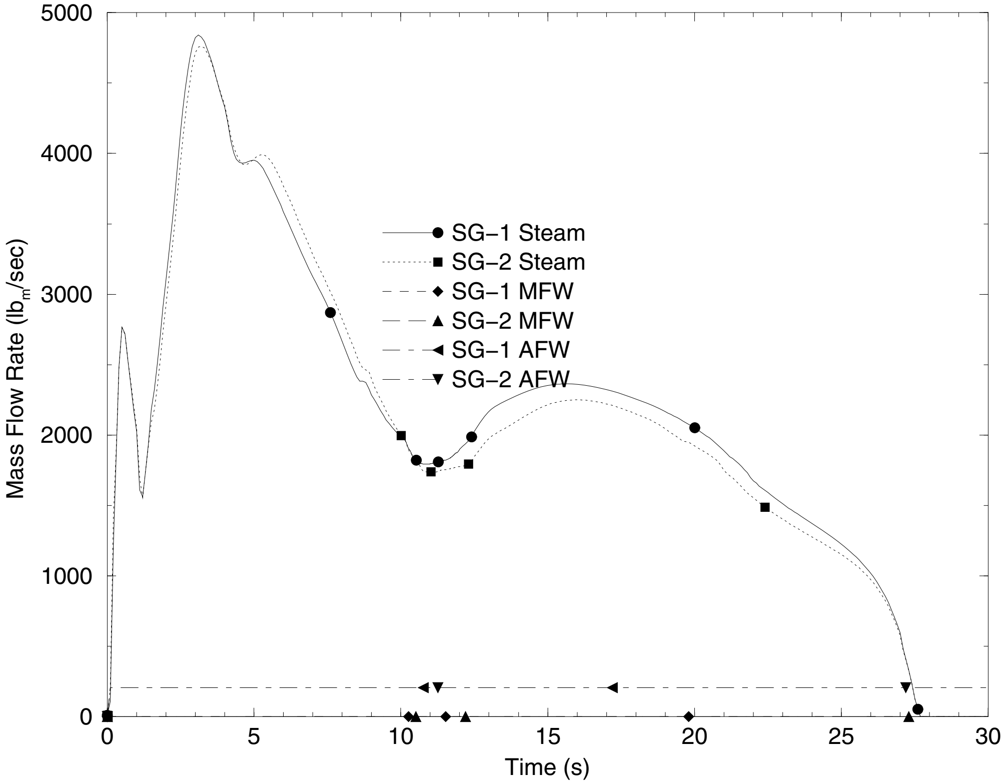


Figure 2.8.5.1.1-8
Increase in Steam Flow (HZP)
Reactivity Feedback

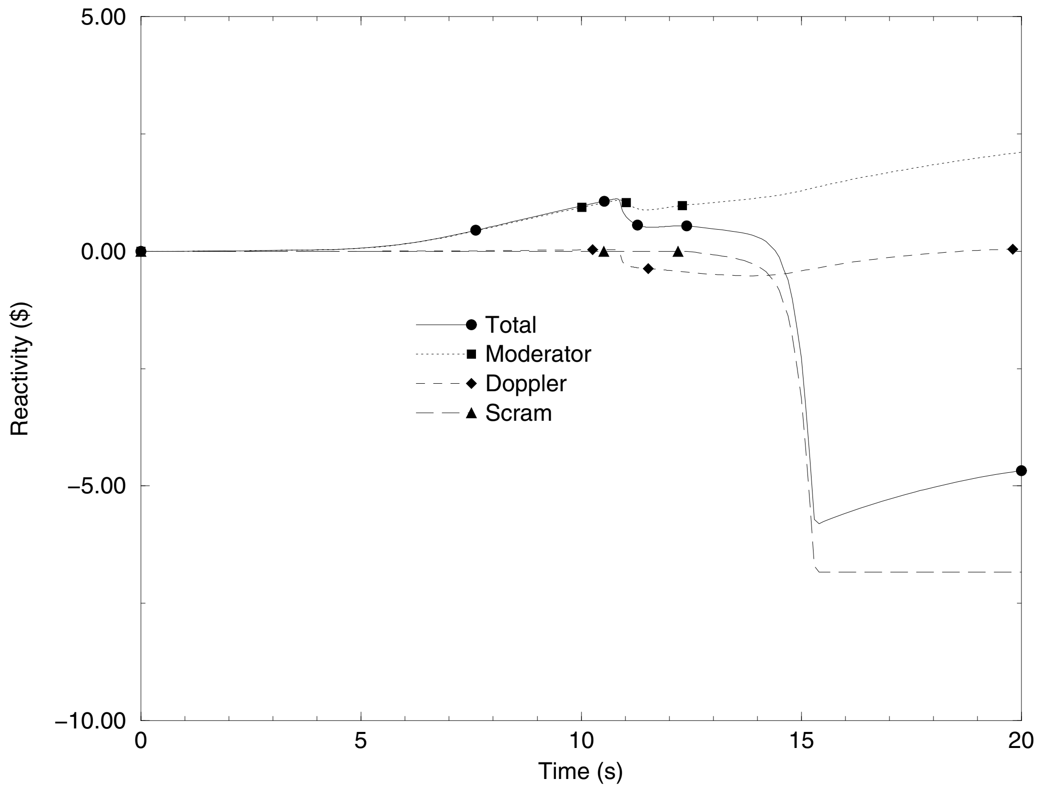


Figure 2.8.5.1.1-9
Increase in Steam Flow (HZP)
Peak Fuel Centerline Temperature

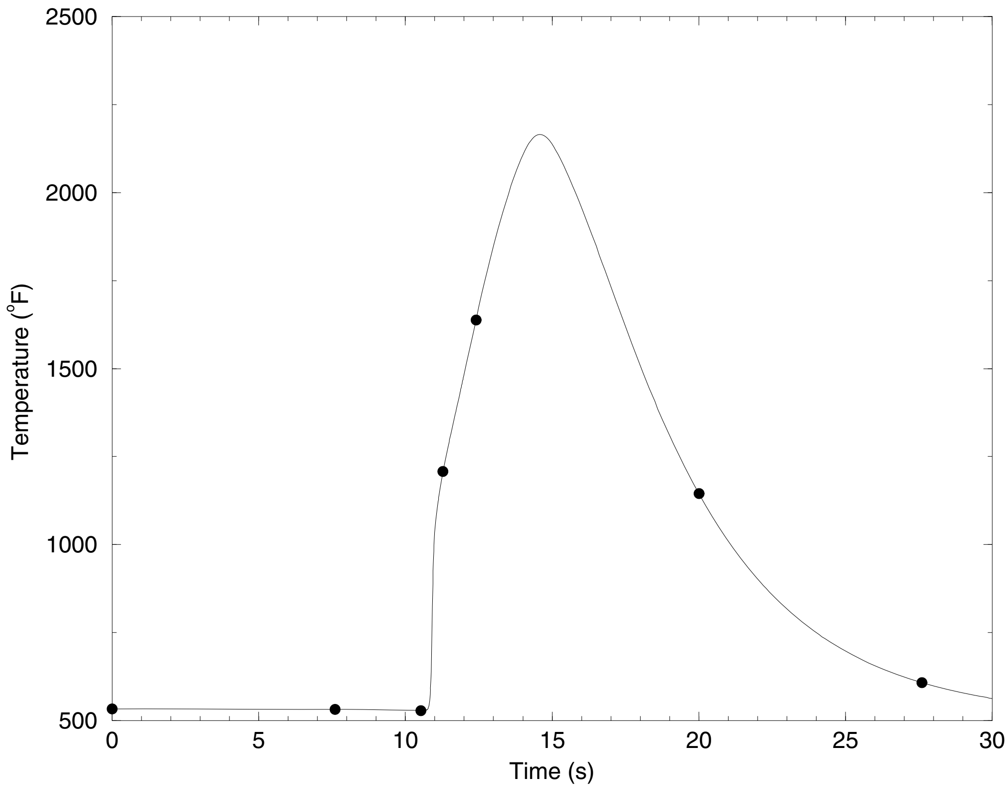


Figure 2.8.5.1.1-10
Increase in Steam Flow (HFP)
Reactor Power

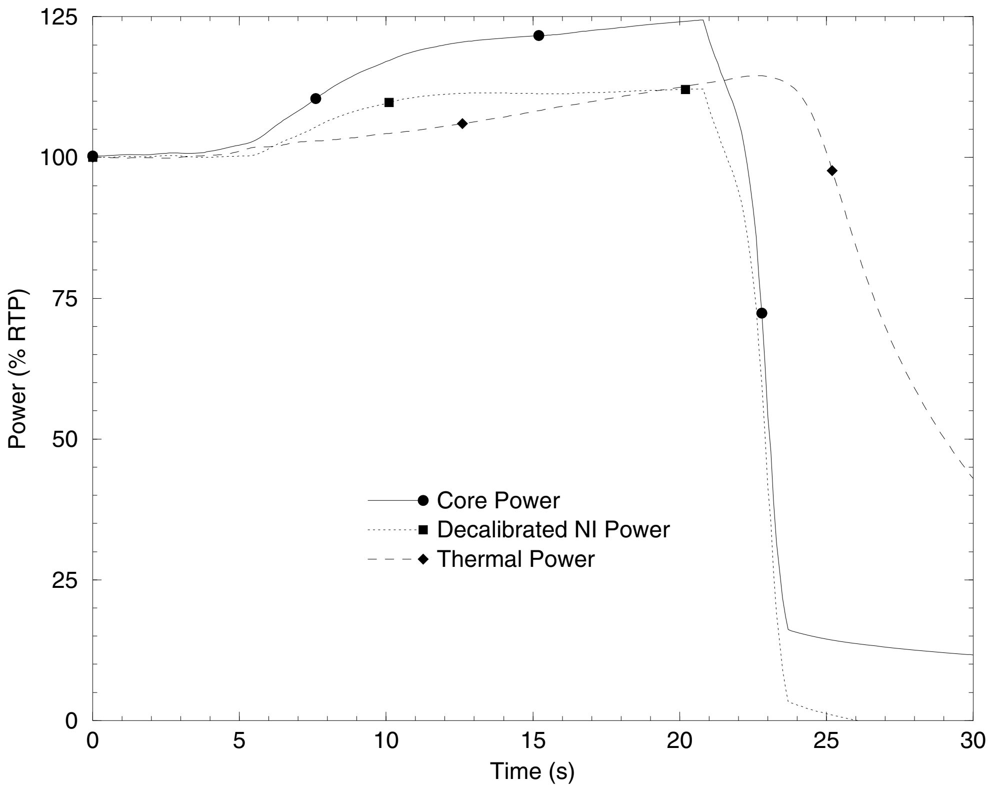


Figure 2.8.5.1.1-11
Increase in Steam Flow (HFP)
Total Core Heat Flux Power

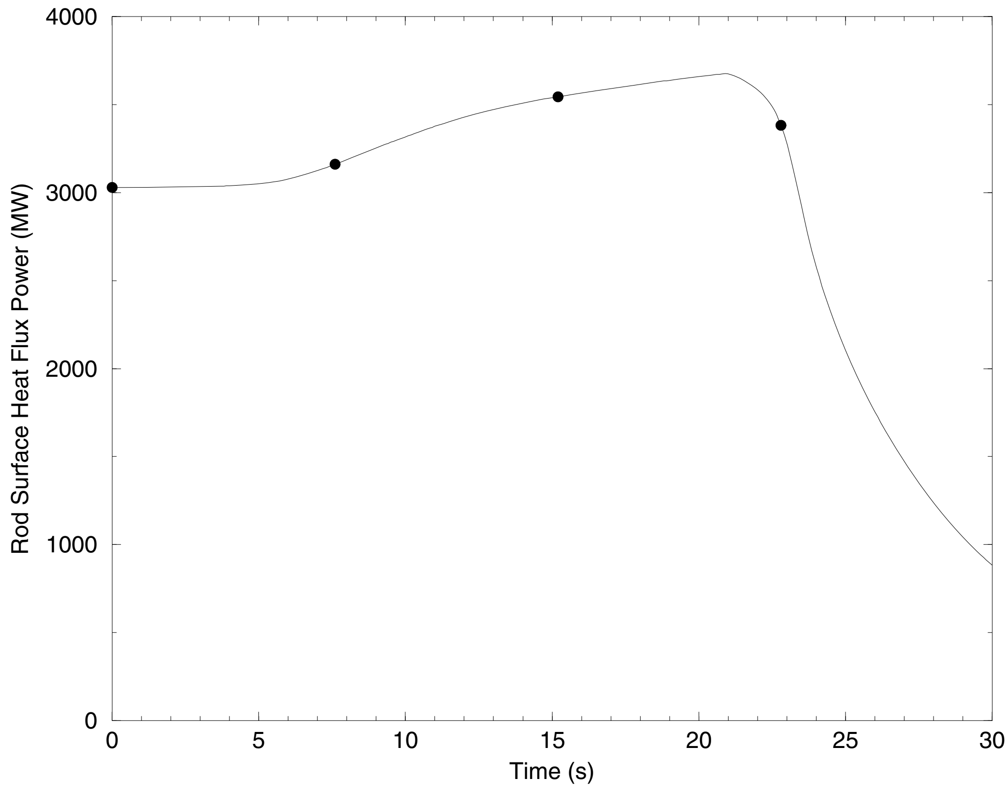


Figure 2.8.5.1.1-12
Increase in Steam Flow (HFP)
Pressurizer Pressure

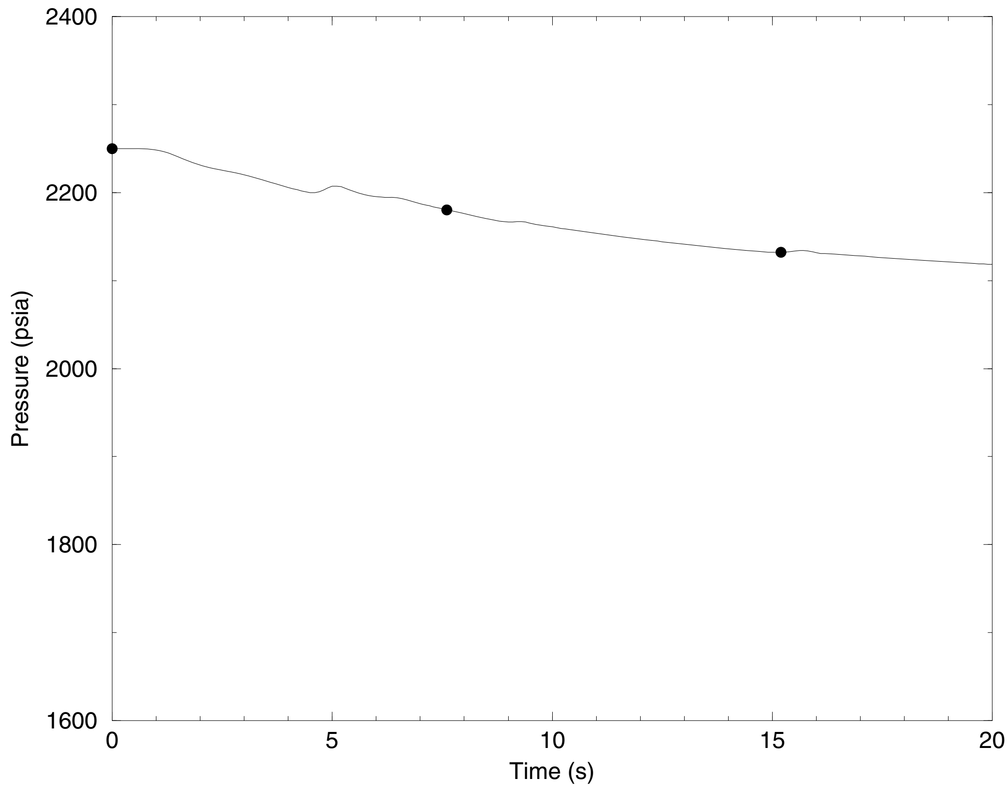


Figure 2.8.5.1.1-13
Increase in Steam Flow (HFP)
RCS Loop Temperatures

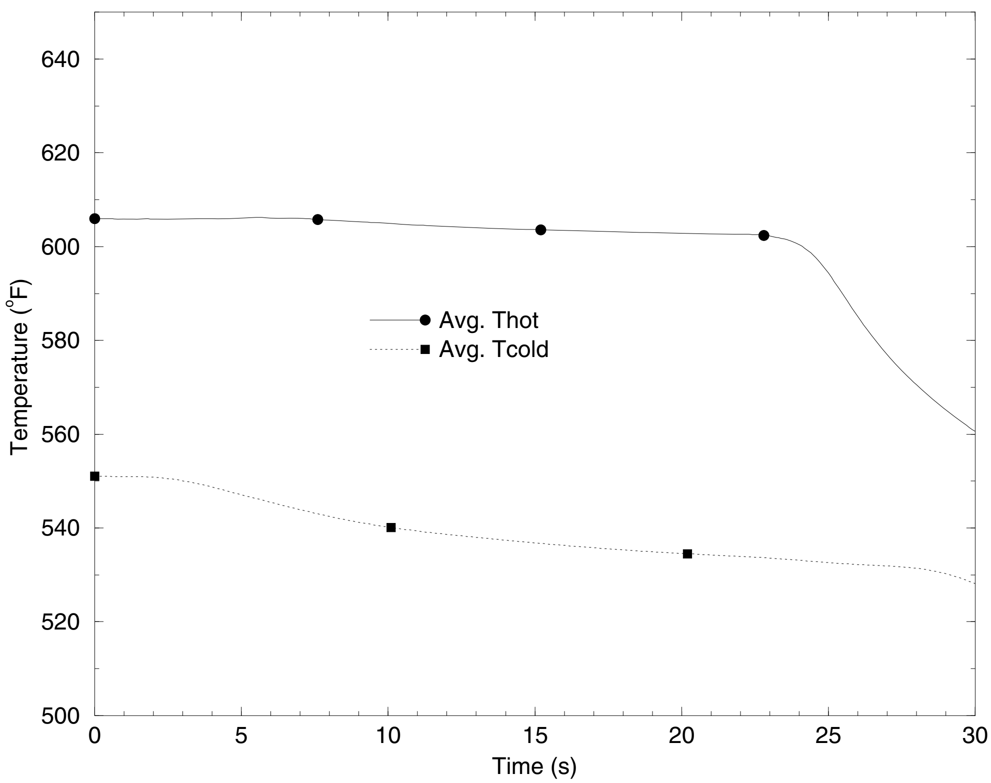


Figure 2.8.5.1.1-14
Increase in Steam Flow (HFP)
RCS Total Loop Flow Rate

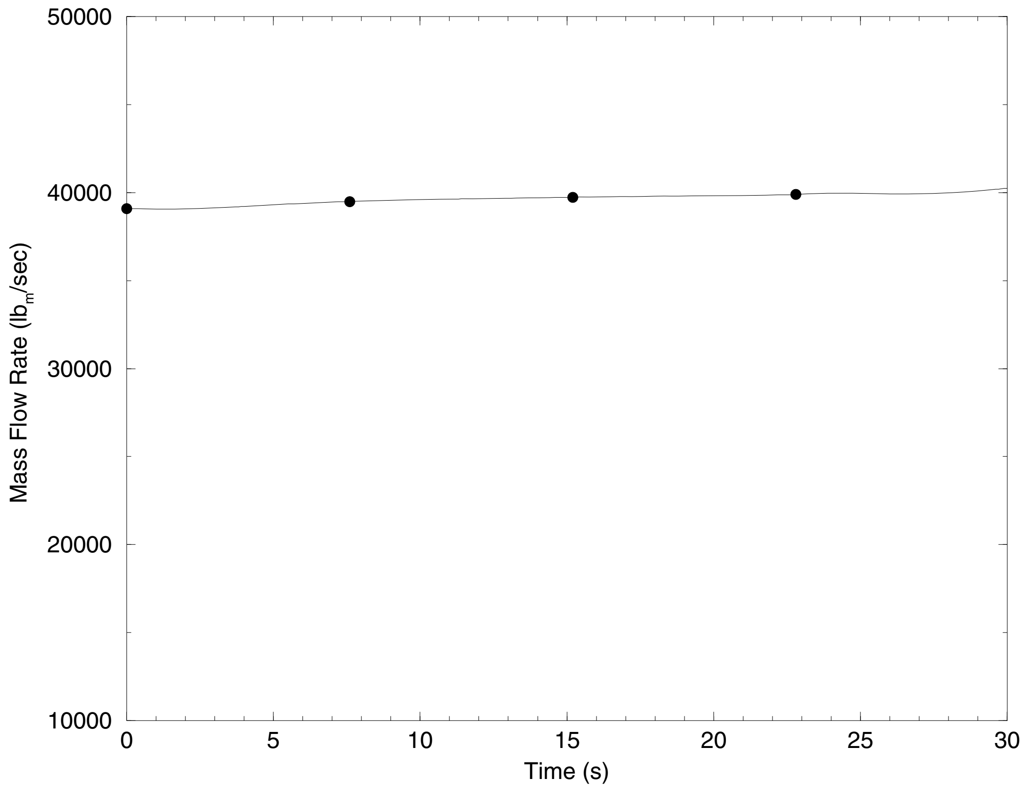


Figure 2.8.5.1.1-15
Increase in Steam Flow (HFP)
Steam Generator Pressures

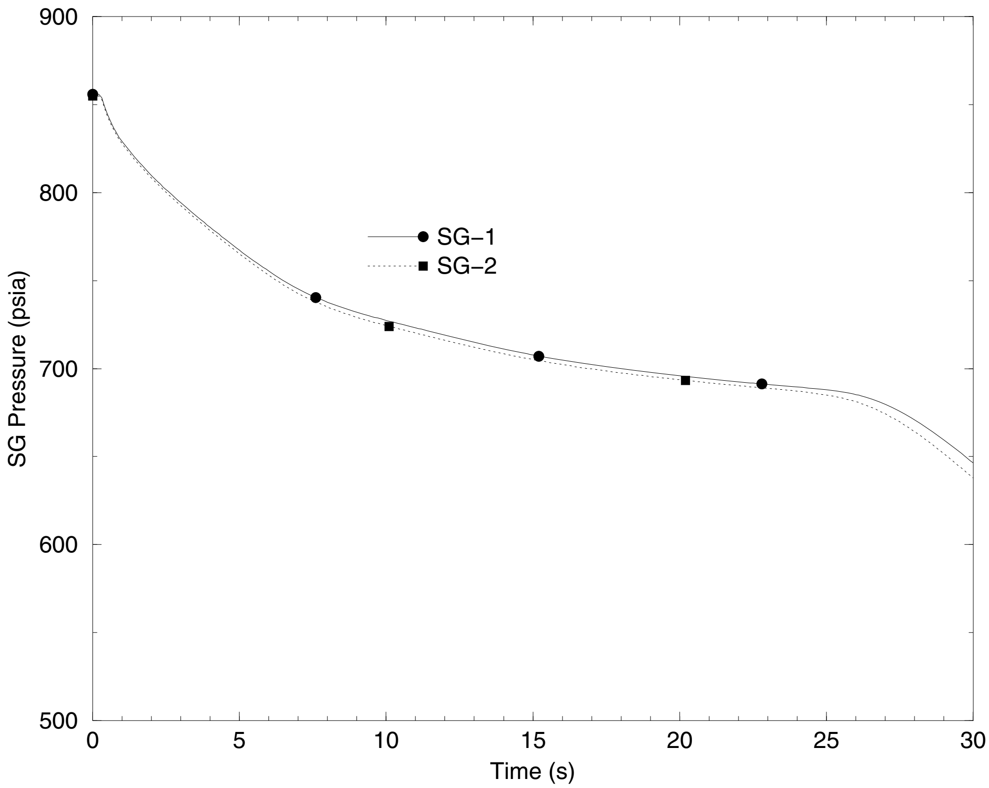


Figure 2.8.5.1.1-16
Increase in Steam Flow (HFP)
Steam and Feedwater Flow Rates

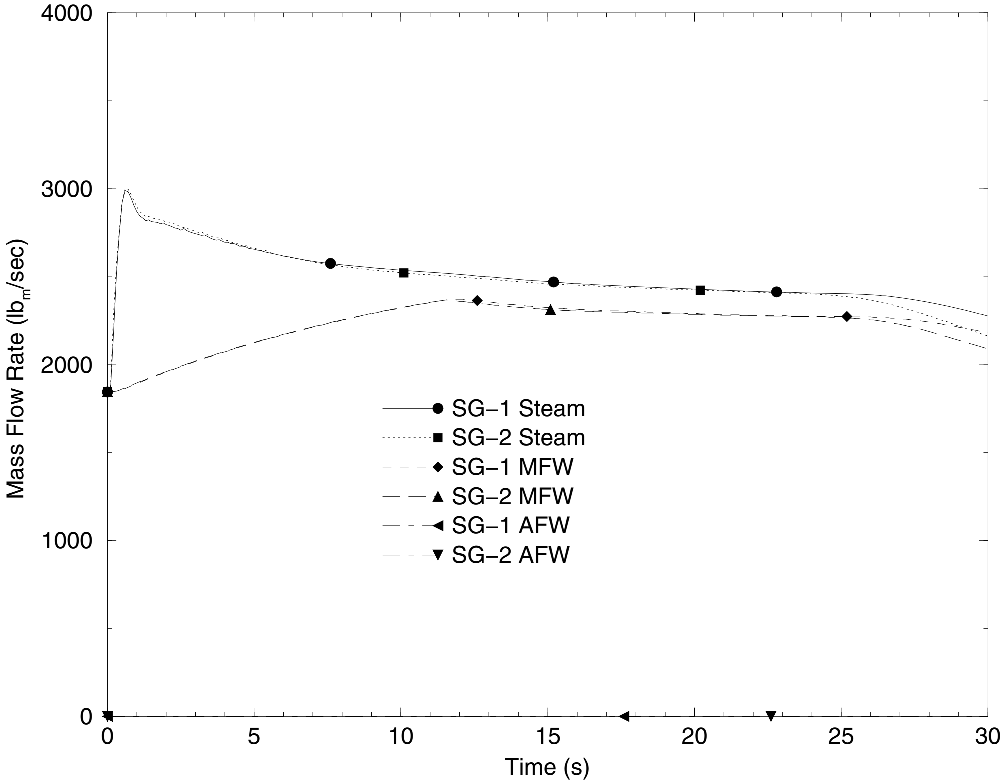


Figure 2.8.5.1.1-17
Increase in Steam Flow (HFP)
Reactivity Feedback

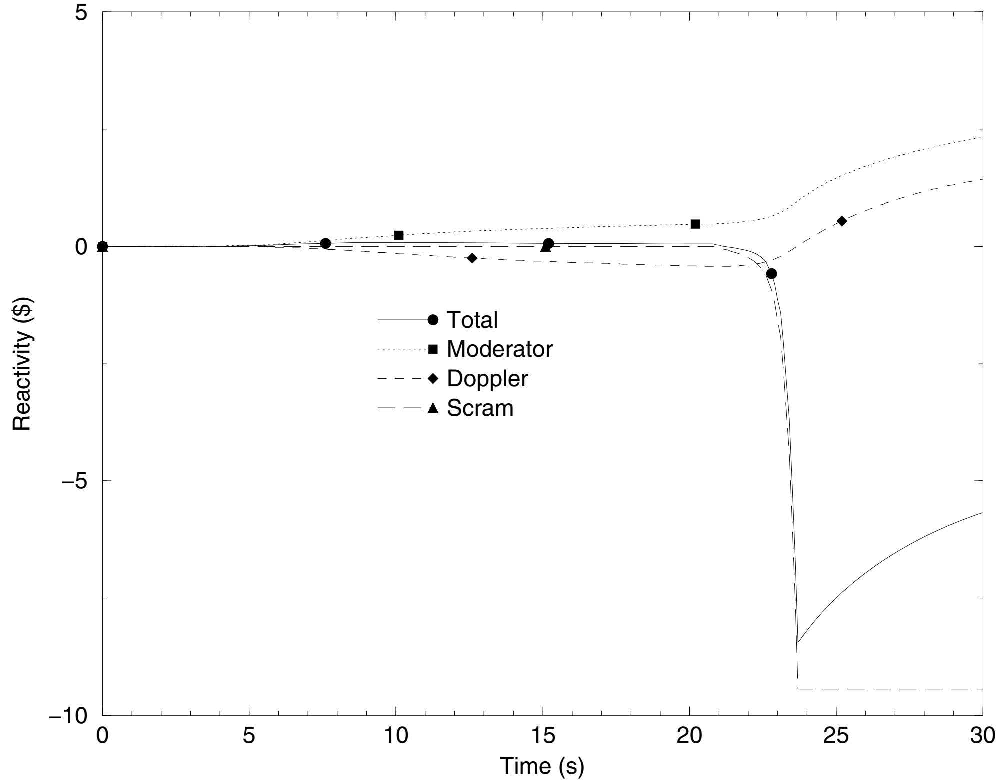


Figure 2.8.5.1.1-18
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Reactor Power

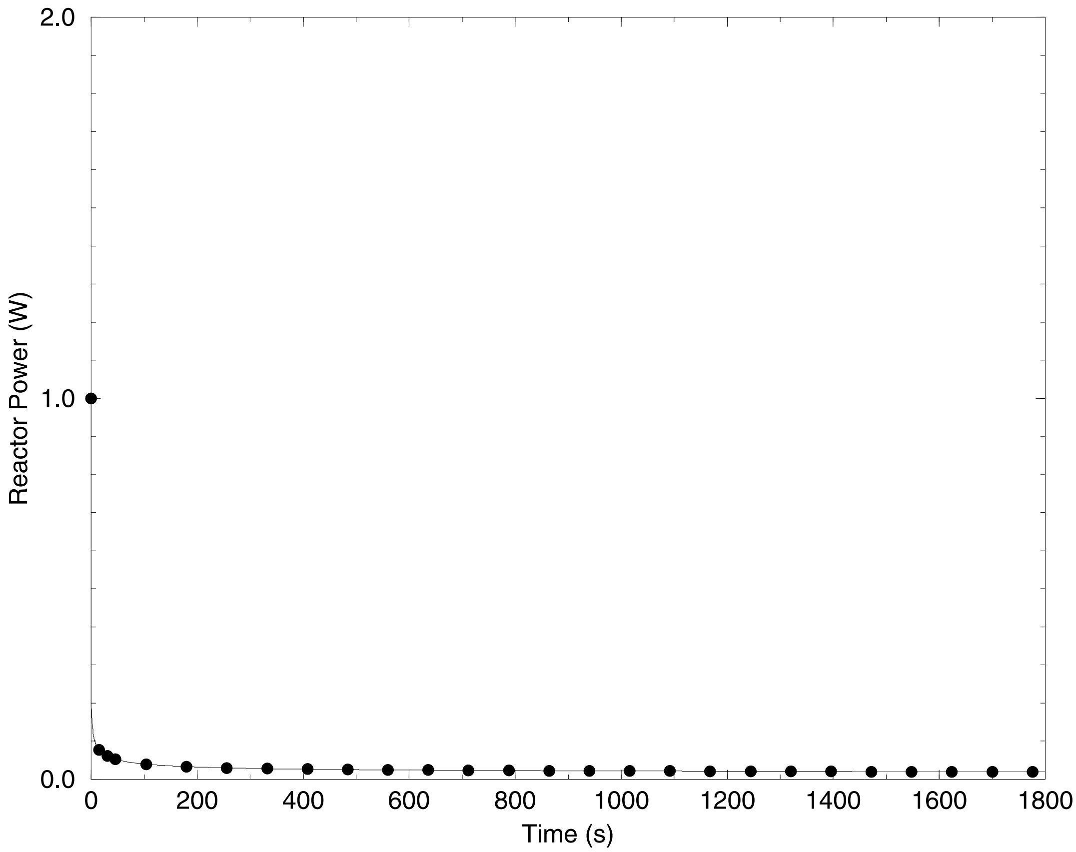


Figure 2.8.5.1.1-19
Inadvertent Opening of a Steam Generator
Relief or Safety Valve
Steam Flow Rates

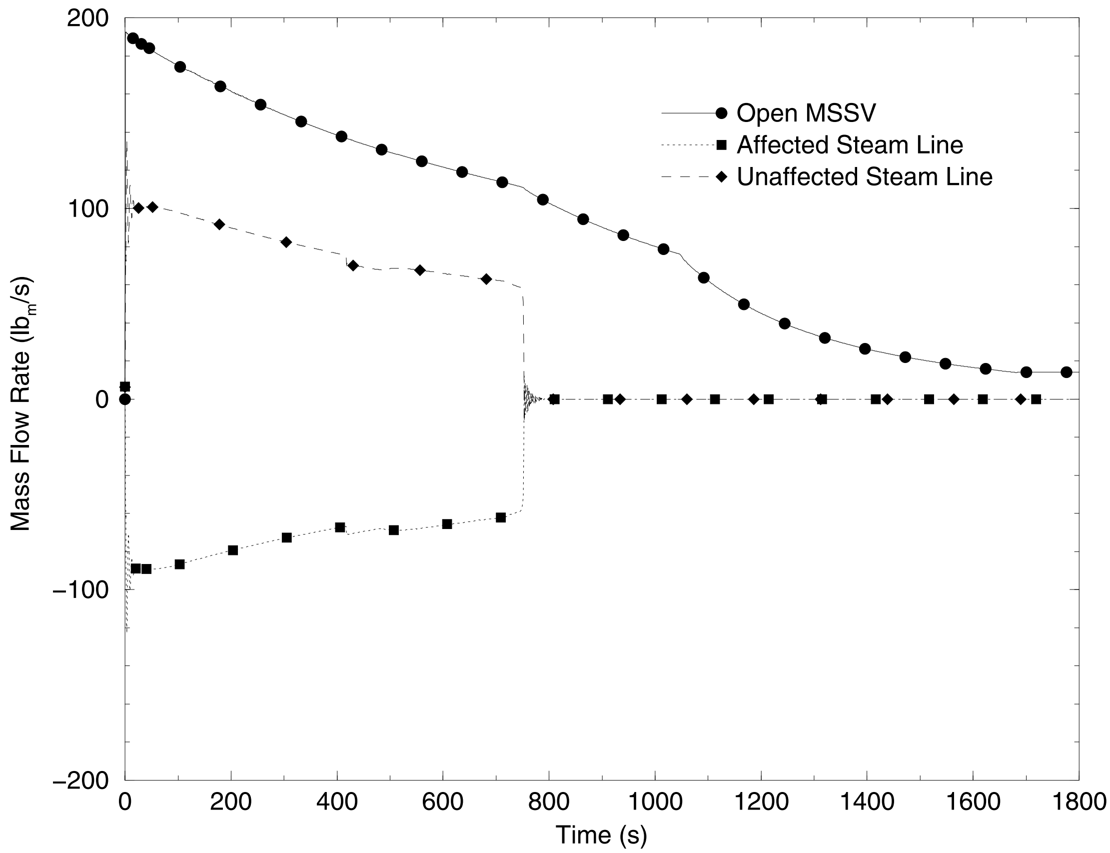


Figure 2.8.5.1.1-20
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Steam Generator Mass Inventories

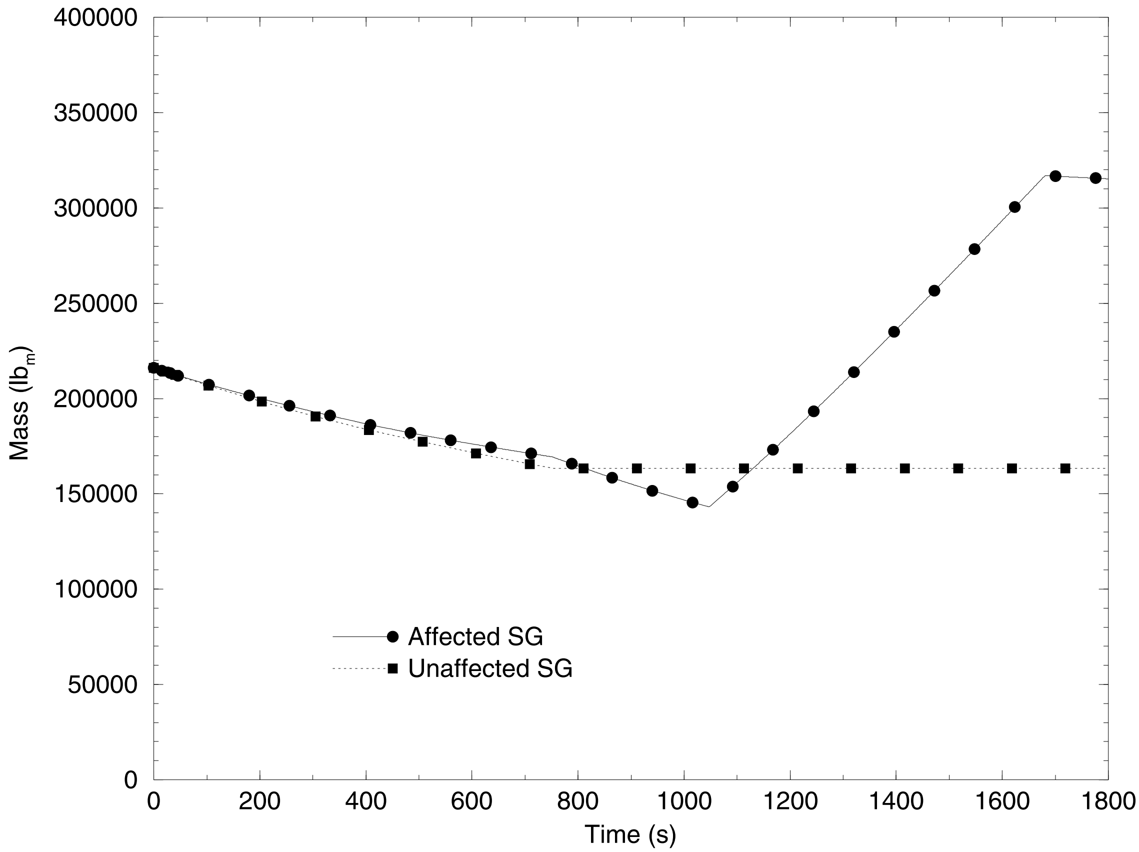


Figure 2.8.5.1.1-21
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Steam Generator Liquid Levels

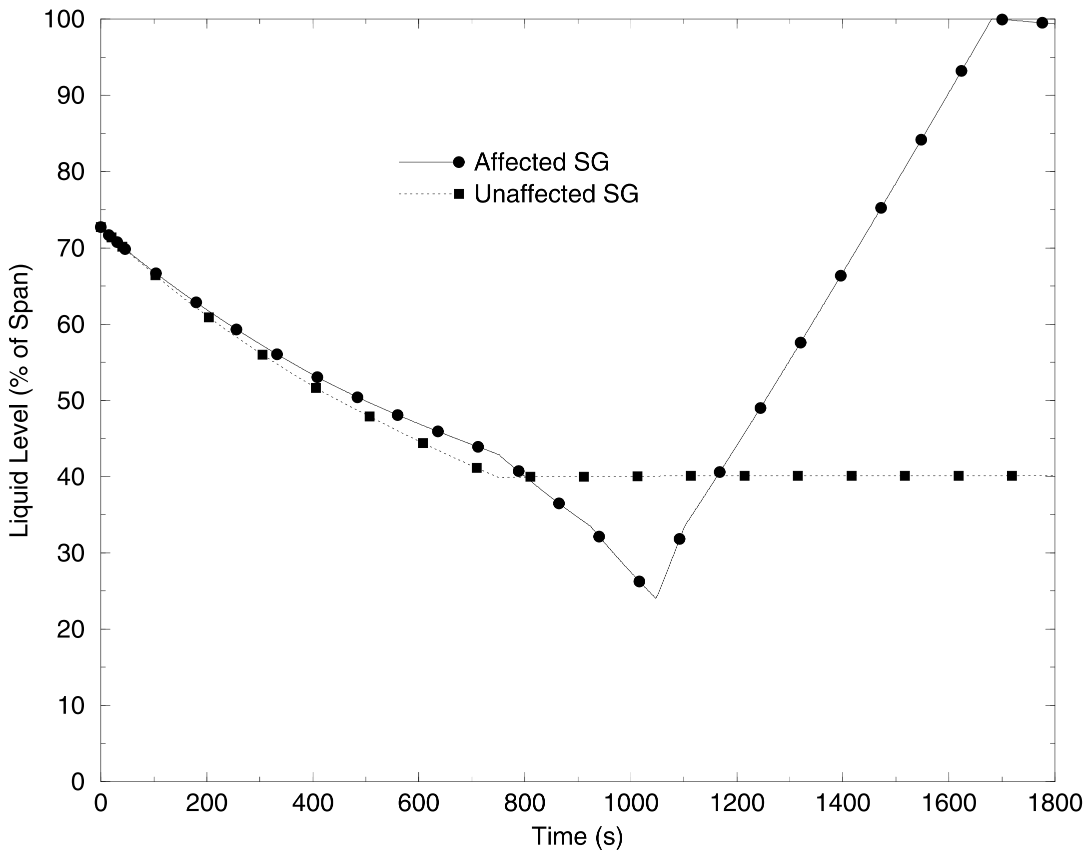


Figure 2.8.5.1.1-22
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Total Feedwater Flow Rate

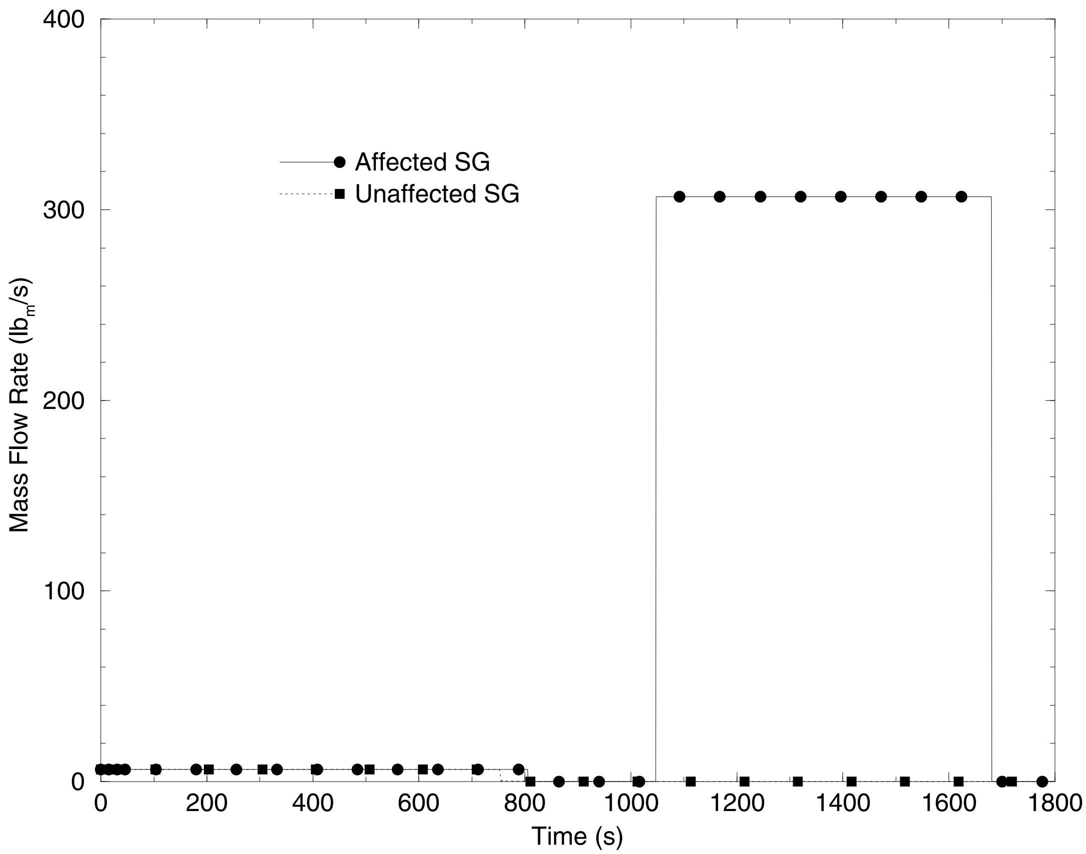


Figure 2.8.5.1.1-23
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Steam Generator Pressures

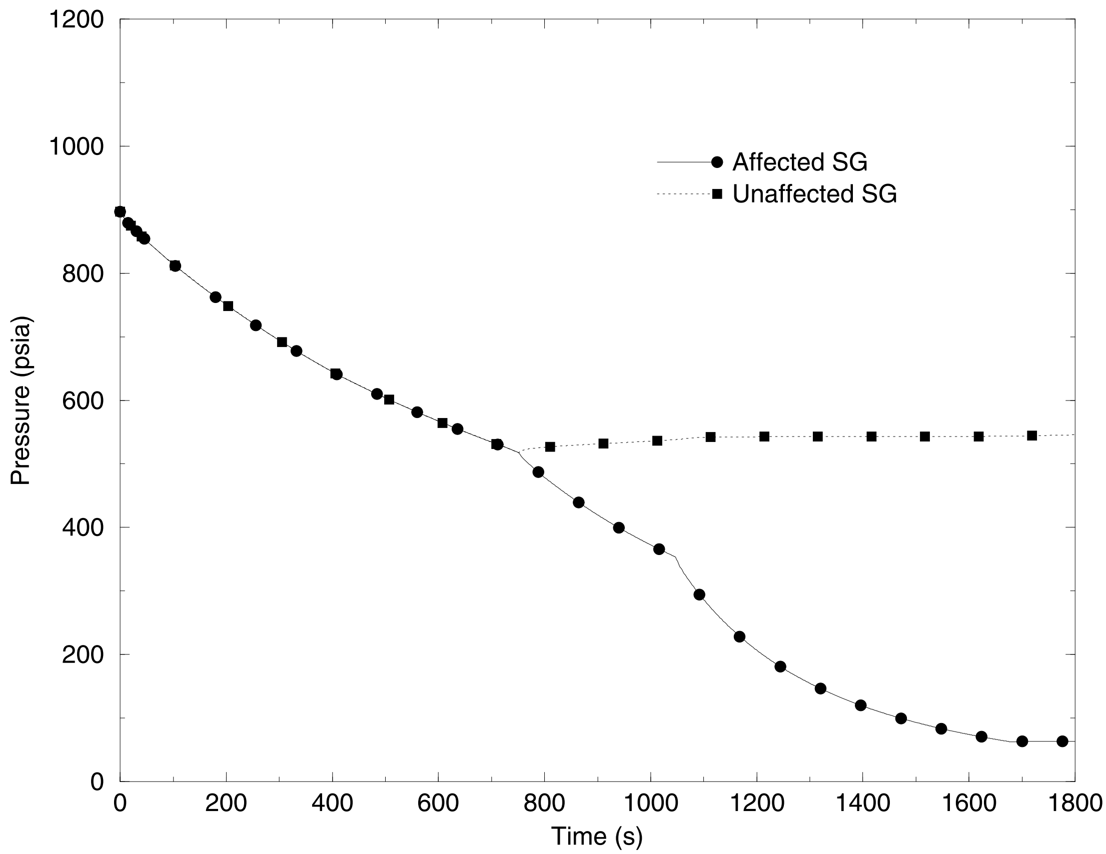


Figure 2.8.5.1.1-24
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Cold Leg Temperatures

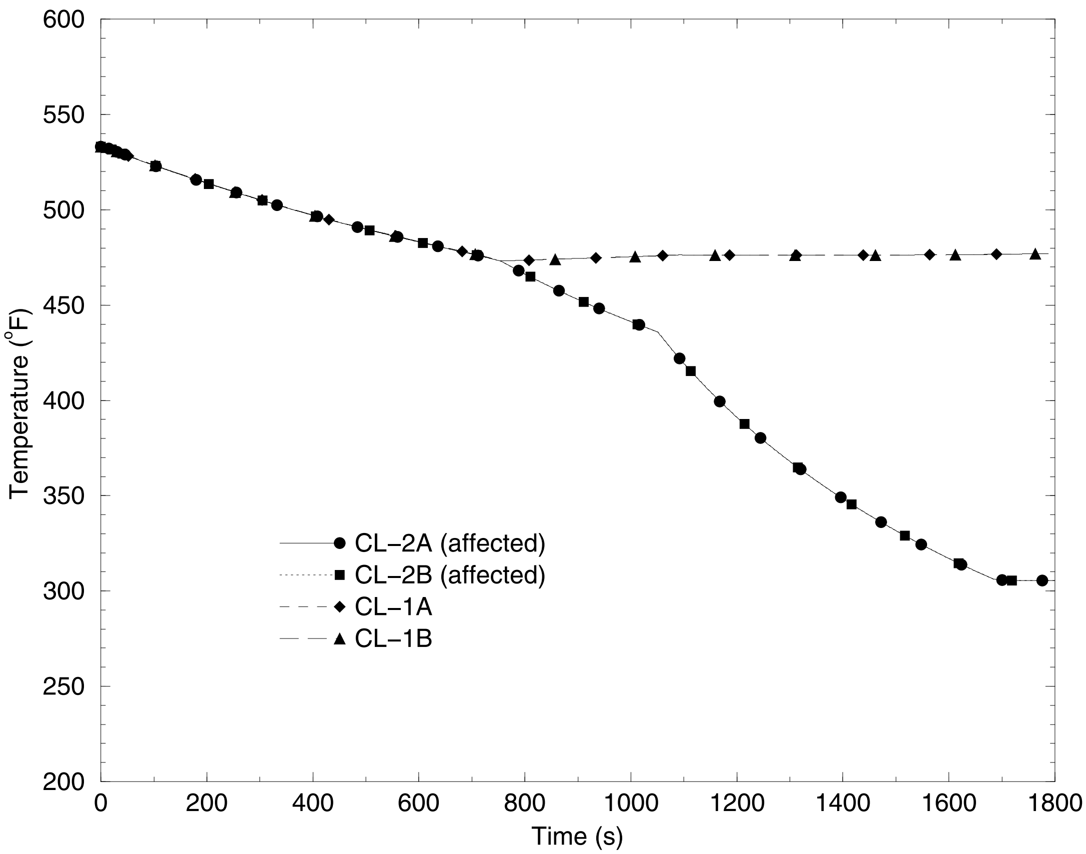


Figure 2.8.5.1.1-25
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Pressurizer Pressure

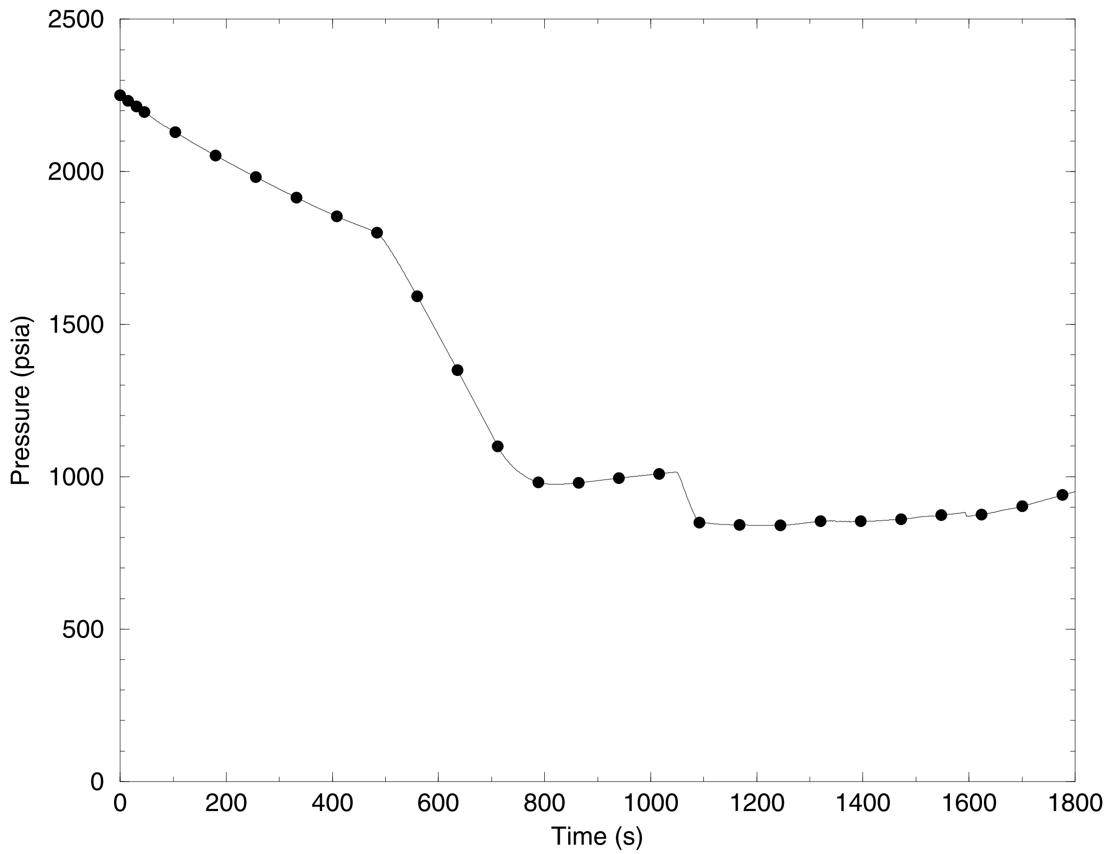


Figure 2.8.5.1.1-26
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Pressurizer Liquid Level

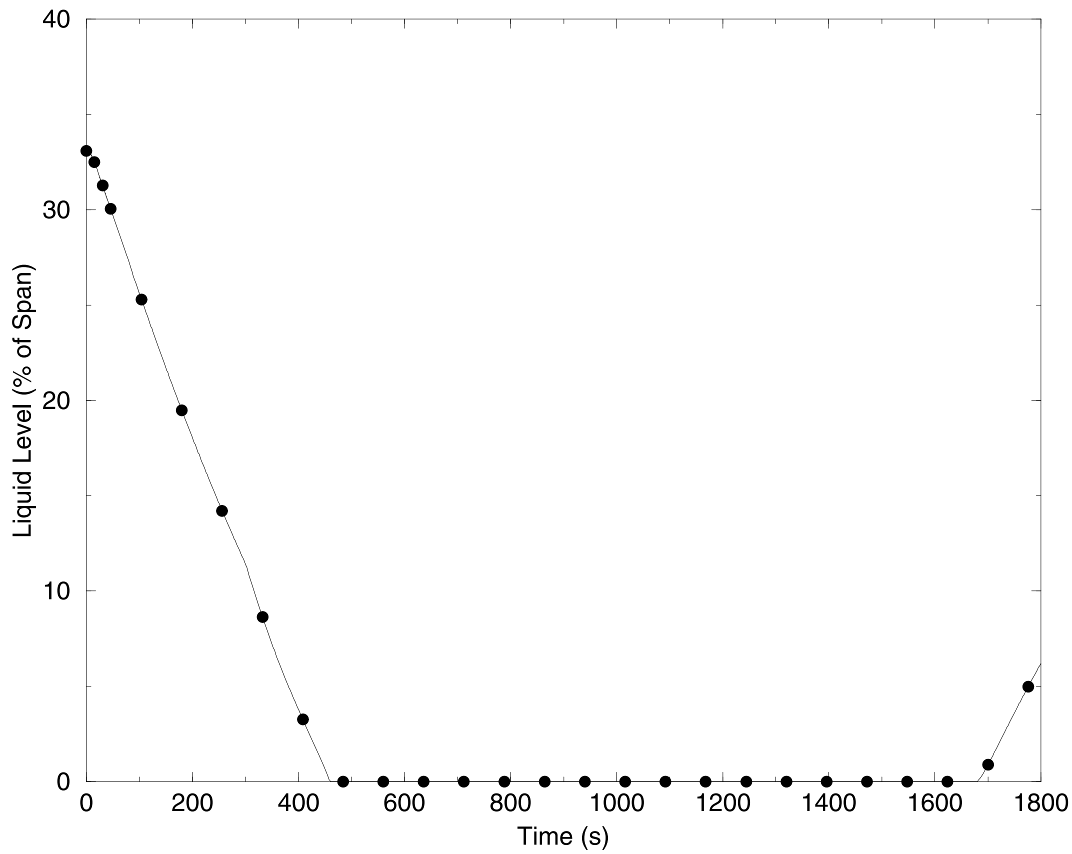


Figure 2.8.5.1.1-27
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Total HPSI Flow Rate

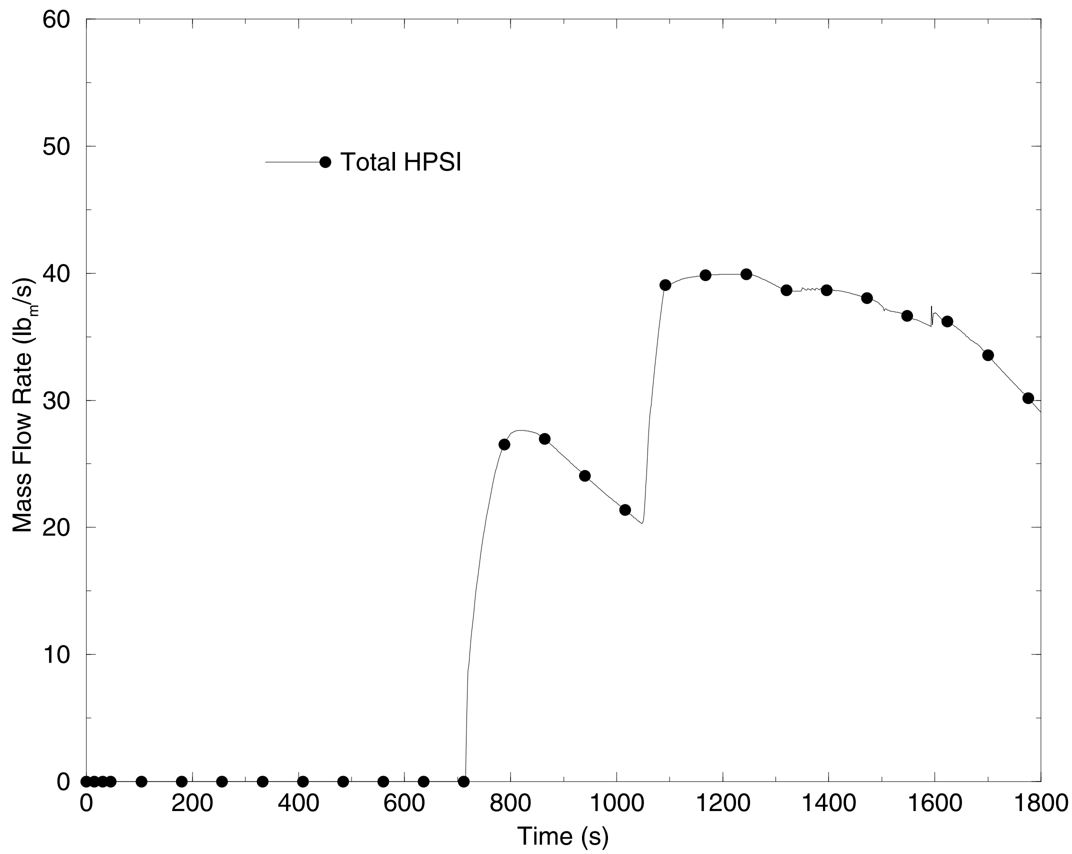
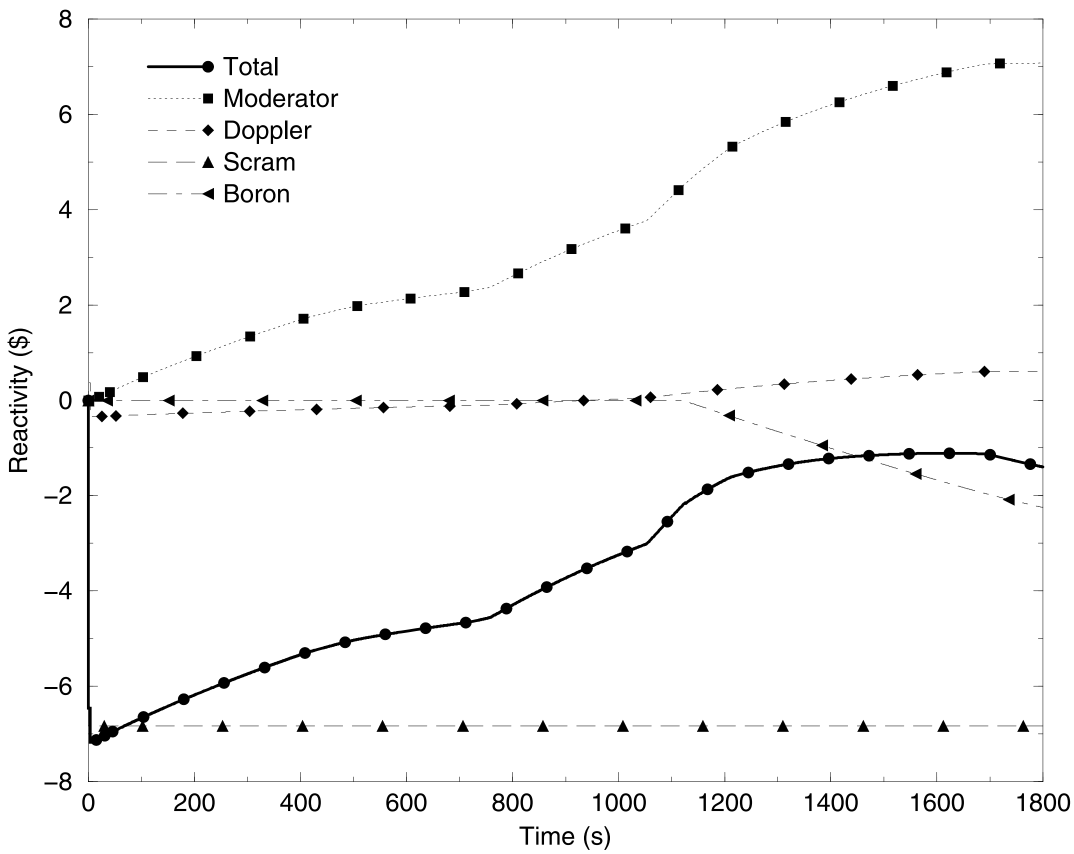


Figure 2.8.5.1.1-28
Inadvertent Opening of a Steam Generator Relief or Safety Valve
Reactivity Feedback



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.

FPL's 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,
- 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:

- 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;
- GDC-35, insofar as it requires the reactor cooling system (RCS) and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in SRP Section 15.1.5 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC relevant to steam system piping failures inside and outside containment are:

- 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of control element assemblies (CEAs) and soluble boron 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.

During an accident, the safety injection system functions to inject concentrated boric acid into the RCS for long term and short 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 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 minimum value. The CEAs are divided into shutdown groups and regulating groups. Administrative procedures and interlocks ensure that only one group is withdrawn at a time, and that 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 7.1.1.

The maximum rate of reactivity addition which may be produced by the chemical and volume control system (CVCS) is too low to induce any significant pressure forces which might degrade the RCPB leak tightness integrity or disturb the reactor vessel intervals. UFSAR Section 9.3.4 describes the design bases of the CVCS.

The RCPB described in UFSAR Chapter 5 and the reactor vessel internals described in UFSAR Chapter 4 can 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 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 constructed in accordance with the applicable codes and comply with the test and inspection requirements of these codes. These test 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 code requirements are performed. The tests and inspection performed on the reactor vessel are summarized in UFSAR Sections 5.4.5 and 5.4.6.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel.

- 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 ECCS is discussed in detail in UFSAR Sections 6.3.2 and 6.3.3. The system is designed to prevent fuel and clad damage that would interfere with the emergency core cooling function for the full spectrum of break sizes, and to limit metal-water reaction. Each of the subsystems is fully redundant. The ECCS design satisfies the criteria specified in 10 CFR 50, Appendix K.

Discussion of the steam line break accident is provided in UFSAR Section 15.4.6. Discussion of minor secondary system pipe breaks is provided 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.

2.8.5.1.2.2 Technical Evaluation

2.8.5.1.2.2.1 Introduction

This event is initiated by a postulated break in a main steam line. If the break is located upstream of a main steam check valve, steam flows to the break from only the affected steam generator (SG) (because the check valve precludes backflow to the break from the unaffected steam generator). The steam flow from the affected SG increases because of the break, but the steam flow from the unaffected SG may also increase to compensate for the reduced steam flow to the turbine from the affected SG. If, on the other hand, the break is located downstream of the main steam check valves, the steam flows from both SGs increase.

The increased steam flows depressurize the SGs. The resultant primary coolant cooldown, in conjunction with a negative moderator temperature coefficient (MTC), causes the reactor power to increase. A reactor trip occurs due to high indicated power, asymmetric SG pressure, or high containment pressure, thus, terminating the power excursion. The increased reactor power and, if the cooldown is asymmetric, the augmented radial power peaking reduce the margin to departure from nucleate boiling (DNB) and fuel centerline melt (FCM). The margin to DNB may further be reduced by an RCS flow coastdown, triggered by a postulated loss of offsite power when reactor scram occurs.

After reactor scram, the affected SG pressure and temperature will continue to decrease rapidly. The drop in SG pressure will initiate a main steam isolation signal (MSIS). Following appropriate delays, the main steam isolation valves (MSIVs) on both the affected and unaffected SGs will close and terminate the blowdown from the unaffected SG.

The cooldown of the RCS will insert positive reactivity from both moderator and fuel temperature reactivity feedbacks (particularly at end of cycle (EOC) conditions with a most-negative MTC). The magnitude of core subcriticality depends on the scram worth and the moderator and fuel temperature reactivity feedbacks.

With the most reactive control rod assumed to be stuck out of the core, the radial neutron flux (and, therefore, power) distribution will be highly peaked in the region of the stuck control rod. The consequences would be most limiting if the core sector with the stuck control rod is also the sector being cooled primarily with coolant delivered to the cold leg of the affected loop.

The event will be terminated by the injection of boron from high pressure safety injection pumps and/or by the dryout of the affected steam generator which will stop the RCS cooldown.

Consistent with the current analysis of record, no credit is taken for automatic isolation of auxiliary feedwater (AFW) on SG differential pressure, and AFW flow is assumed to be isolated at 10 minutes by operator action (thereby reducing the primary-to-secondary heat transfer to the affected SG).

2.8.5.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The parameters and equipment states were chosen to provide conservative calculation of fuel failures. The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – For the pre-scram analysis, the event was initiated from rated power plus uncertainty conditions with a maximum core inlet temperature and minimum Technical Specification (TS) RCS flow. This set of conditions minimizes the initial margin to DNB. Loss of offsite power was assumed at the time of turbine trip resulting in the coastdown of the reactor coolant pumps (RCPs).

  For the post-scram analysis, two sets of initial conditions were considered. First, the event was assumed to initiate from rated power conditions with a maximum core inlet temperature. Rated power conditions (i.e., coolant temperatures) represent the largest potential cooldown and consequential reactivity insertion. A second set of conditions assumed that the event initiated from a hot zero power condition with the minimum allowed TS shutdown margin. For both hot full power (HFP) and hot zero power (HZP) initial conditions, cases were run both with and without offsite power.

- Break Size and Location – For the pre-scram analysis, a full range of break sizes, up to a full guillotine break of a main steam line, was considered to determine the most limiting combination of break size and MTC based on the amount of fuel failure. Breaks were modeled both upstream and downstream of the MSIVs.

  For the post-scram analysis, a full double-ended guillotine break of a main steam line upstream of the MSIV was considered. The blowdown of the SG is limited by the flow area of the integral flow restrictor. This break size and location produces the largest cooldown which maximizes the potential return-to-power.

- Break Flow – Moody critical flow model was applied at the SG integral flow restrictor. The break was modeled to maximize break flow and rate of cooldown. Steam-only flow out the break was also assumed to maximize the secondary and RCS cooldown rate.

- Reactivity Feedback – This event is primarily driven by moderator feedback as a result of the cooldown of the RCS. For the pre-scram analysis, a bounding range of negative MTC values was considered including the most negative TS limit of -32 pcm/°F. For the post-scram analysis, the most negative TS limit of -32 pcm/°F was modeled. Minimum scram worth, appropriate for the assumed initial condition, was assumed. For the post-scram analyses, the most reactive rod was assumed to be stuck out of the core.

- Reactor Protection System (RPS) Trips and Delays – RPS trip setpoints and delay times were biased to conservatively delay the initiation of scram. In addition, harsh containment conditions were considered, such that increased uncertainties were included in the trip setpoints of the credited trips. The analysis included the effect of power decalibration for both the nuclear instrumentation (NI)-power (due to excore detector decalibration, as a result of the severe overcooling of the fluid in the reactor vessel downcomer) and T-power (due to lagged temperature signals).

- Gap Conductance – Gap conductance was set to a conservative EOC value to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.
- Steam Generator Tube Plugging (SGTP) – No SGTP was assumed so as to maximize the primary-to-secondary side heat transfer, which exacerbates the reactivity insertion due to moderator feedback.
- RCS Flow – Cases with all RCPs running (offsite power available) and with all RCPs stopped (loss of offsite power) were analyzed to evaluate the effects of RCS flow during the post-scram phase of the event.
- Single Failure – For the pre-scram analysis, a single failure of one of the four NI detectors was assumed such that reactor trip was conservatively delayed. For the post-scram analysis, a single failure of one of the two high pressure safety injection (HPSI) pumps required to be operable during plant normal operation was assumed. This single failure assumption resulted in an additional delay for boron to reach the core.

The principally challenged acceptance criterion for this event is the radiological consequences. The analysis documented herein does not address radiological consequences directly; rather, the extent of fuel failure is determined which is an input to the radiological dose analyses in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST). In addition, steam releases were calculated for input to the radiological dose analyses based on a plant cooldown to 212°F.

2.8.5.1.2.2.3 Description of Analyses and Evaluations

This event has two distinct phases, i.e., prior to reactor scram or “pre-scram” and after reactor scram or “post-scram”. Each of these phases was analyzed to assess the impact to fuel failure for the EPU.

The previous analysis was based on the ANF-RELAP methodology (Reference 1). For the extended power uprate (EPU), detailed analyses were performed with approved methodology (Reference 2), which consists mainly of four computer codes. The S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures) and produce an estimated time of minimum departure from nucleate boiling ratio (MDNBR). The RODEX2 code is used primarily to establish the gap coefficients for use in the S-RELAP5 code. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code, which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 3) for the pre-scram cases and the Modified Barnett correlation (Reference 4) for the post-scram cases. The PRISM code was used to calculate power distribution information and kinetics parameters.

Pre-Scram

The event was analyzed from HFP conditions to assess the potential amount of fuel failure due to DNB and fuel melting. A full range of break sizes, up to the double-ended guillotine break of a main steam line, was considered in the analysis with the following break locations:

- Break located inside containment and upstream of an MSIV
- Break located outside containment and upstream of an MSIV
- Break located downstream of an MSIV.

Also, a range of negative MTC values was considered including the most negative TS/core operating limits report (COLR) limit of -32 pcm/°F. From the calculations, the most limiting combination of break size and MTC was determined based on the amount of fuel failure. Loss of offsite power was assumed to occur coincident with reactor scram in order to produce a conservative MDNBR.

Post-Scram

The event was analyzed from both HZP and HFP conditions to assess the potential amount of fuel failure. Offsite power available and loss of offsite power cases were considered. Loss of offsite power was assumed at event initiation. The largest break size in combination with the most negative TS/COLR MTC limit of -32 pcm/°F was analyzed. Breaks located inside or outside containment were bounded because harsh conditions were assumed for all cases.

2.8.5.1.2.2.4 Evaluation of 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.

2.8.5.1.2.2.5 Results

Pre-Scram

The limiting case was initiated at HFP conditions by a postulated 3.0 ft^2 break in a main steam line outside the reactor containment and upstream of the main steam check valve with an MTC of -20 pcm/°F. The limiting case was calculated based on the combination of break size, break location and MTC that resulted in the lowest MDNBR and highest peak linear heat rate (LHR). The sequence of events for the limiting case is summarized in LR Table 2.8.5.1.2-1.

Key system parameters illustrating the transient are presented in LR Figures 2.8.5.1.2-1 through 2.8.5.1.2-10. LR Figure 2.8.5.1.2-1 shows the core power, NI power and thermal power response as a function of time. Reactor trip occurs on a variable high power (VHP) signal based on thermal power. LR Figure 2.8.5.1.2-2 shows core power based on rod surface heat flux. LR Figure 2.8.5.1.2-3 shows the pressurizer pressure and LR Figure 2.8.5.1.2-4 shows the pressurizer level responses. LR Figure 2.8.5.1.2-5 shows the hot and cold leg temperatures. LR Figure 2.8.5.1.2-6 shows the total RCS flow rate where RCP coastdown occurs with an assumed loss of offsite power at the time of turbine trip. LR Figures 2.8.5.1.2-7 through 2.8.5.1.2-10 show the SG pressures, the break flow, the steam and feedwater flow rates, and the reactivity feedback, respectively.

The results of this analysis are given in LR Table 2.8.5.1.2-2. Several statepoints were chosen at and near the time of maximum core power. The MDNBR was calculated to be less than the 95/95 limit for the HTP DNB correlation resulting in one fuel assembly, or 0.461% of the core, failing. The peak LHR was calculated to be less than the FCM limit; thus, no fuel failure due to FCM was predicted to occur. The fuel failures calculated here meet the fuel failure limits in the radiological dose analyses documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

LR Table 2.8.5.1.2-2 provides a comparison of the EPU results to the previous analysis described in the UFSAR Section 15.4.6.

Post-Scram

The sequences of events are summarized in LR Table 2.8.5.1.2-3 for the cases initiated from HZP, both with and without offsite power. LR Table 2.8.5.1.2-4 summarizes the sequences of events for the cases initiated from HFP, both with and without offsite power.

The greatest challenge to the FCM limit occurred for the case initiated from HZP with offsite power available. Key system parameters illustrating the transient are presented in LR Figures 2.8.5.1.2-11 through 2.8.5.1.2-20. LR Figure 2.8.5.1.2-11 shows the break flow rates as a function of time. LR Figures 2.8.5.1.2-12 through 2.8.5.1.2-19 show the SG pressures, the feedwater flow rates to each steam generator, the SG mass inventories, the core inlet temperatures for the affected and unaffected loops, the pressurizer liquid level, the pressurizer pressure responses, the total HPSI flow rate, and the reactivity feedback during the event, respectively. LR Figure 2.8.5.1.2-20 shows the total core power as well as powers for the stuck rod, affected and unaffected regions. The FCM limit of 22.279 kW/ft is the calculated limit to preclude FCM across all fuel types. In the HZP Post-trip main steam line break (MSLB) case, an evaluation was performed on a pin type specific basis which demonstrated that FCM was precluded for a peak LHR of 23.342 kW/ft.

The greatest challenge to the departure from nucleate boiling ratio (DNBR) limit occurred for the case initiated from HZP with a loss of offsite power. Key system parameters illustrating the transient for the limiting cases are presented in LR Figures 2.8.5.1.2-21 through 2.8.5.1.2-30. LR Figure 2.8.5.1.2-21 shows the break flow rates as a function of time. LR Figures 2.8.5.1.2-22 through 2.8.5.1.2-29 show the SG pressures, the feedwater flow rates to each SG, the SG mass inventories, the core inlet temperatures for the affected and unaffected loops, the pressurizer liquid level, the pressurizer pressure responses, the total HPSI flow rate, and the reactivity feedback during the event, respectively. LR Figure 2.8.5.1.2-30 shows the total core power as well as powers for the stuck rod, affected and unaffected regions are met.

Results are given in LR Table 2.8.5.1.2-5. Statepoints were chosen at the time of maximum core power after reactor scram. The calculated MDNBRs were greater than the 95/95 limit for the Modified Barnett CHF correlation; thus, no fuel failure due to DNB was predicted to occur. The peak LHRs were evaluated relative to the FCM limit of 22.279 kW/ft which is the calculated limit to preclude fuel centerline melt across all fuel types. As presented in LR Table 2.8.5.1.2-5, the peak LHRs were less than that limit for all cases except the HZP, offsite power available case. Due to exceeding the FCM limit, the HZP, offsite power available case was evaluated on a pin-type specific basis, which determined the amount of fuel failure for the case to be 0.02% of the core. The fuel failures calculated here meet the fuel failure limits in the radiological dose analyses documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

LR Table 2.8.5.1.2-5 provides a comparison of the EPU results to the previous analysis described in the UFSAR Section 15.4.6.

Minor Secondary System Pipe Breaks

A minor secondary system pipe break is defined as one which results in steam blowdown rates equivalent to a 6-inch break outside the containment. The break area is less than the full steam line area for the main steam line break event and any fuel failure predicted for the main steam line break event will bound this event. This event is bounded by the main steam line break event.

2.8.5.1.2.3 Conclusion

FPL has reviewed the analyses of steam system piping failure 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 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. Therefore, FPL finds the proposed EPU acceptable with respect to steam system piping failures.

2.8.5.1.2.4 References

1. EMF-84-093(P)(A), Revision 1, Steam Line Break Methodology for PWRs, Siemens Power Corporation, February 1999.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

4. IN-1412, TID-4500, A Correlation of Rod Bundle Critical Heat Flux for Water in the Pressure Range 150 to 725 psia., Idaho Nuclear Corporation, July 1970.

Table 2.8.5.1.2-1
Pre-Scram Main Steam Line Break
Sequence of Events[1]

Event	**Time (sec)**
Break occurs	0.0
Indicated power (ΔT signal) reached VHP trip setpoint.	23.2
Reactor scram signal received and turbine tripped. Postulated loss of offsite power occurs and reactor coolant pumps begin coastdown.	23.6
Maximum LHR	23.65
CEA insertion begins	24.1
MDNBR	24.85
1. The limiting case is characterized as a 3.0 ft^2 break outside of the reactor containment and upstream of the main steam check valve initiated at HFP with an MTC of -20 pcm/°F.	

Table 2.8.5.1.2-2
Pre-Scram Main Steam Line Break
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis	Limit
MDNBR (%fuel failure)	No fuel failure	0.994 (0.46)	1.164
Peak LHR (%fuel failure)	No fuel failure	21.449 (0)	22.279

Table 2.8.5.1.2-3
HZP Post-Scram Main Steam Line Break
Sequence of Events

Event	Offsite Power Avail. Time (sec.)	Loss of Offsite Power Time (sec.)
DEGB in main steam line occurs upstream of the MSIV, Reactor trip, AFW flow begins (both SGs)	0.0	0.0
CEA insertion begins	0.5	0.5
CEAs fully inserted.	3.4	3.4
MSIS on low SG pressure	10.1	9.5
Low pressurizer pressure ESF trip	14.7	17.8
MSIVs closed	17.0	16.4
Minimum unaffected sector core inlet temperature	20.6	36.0
HPSI begins (unborated water begins to clear from the SI lines)	34.2	47.8
Shutdown worth has been fully overcome by moderator and Doppler feedback	81.0	171.0
Borated HPSI flow begins (unborated water has been cleared from the SI lines)	254.7	---
Peak post-scram reactor power	256.0	234.0
MDNBR	256.0	234.0
Maximum LHR	256.0	234.0
Borated HPSI flow begins (unborated water has been cleared from the SI lines)	---	263.4
Operator terminates AFW. Affected SG mass inventory begins to decrease.	600.0	600.0

Table 2.8.5.1.2-4
HFP Post-Scram Main Steam Line Break
Sequence of Events

Event	Offsite Power Avail. Time (sec.)	Loss of Offsite Power Time (sec.)
DEGB in main steam line occurs upstream of the MSIV	0.0	0.0
Reactor and turbine trip	7.0	11.3
CEA insertion begins	7.5	11.8
CEAs fully inserted.	10.4	14.7
MSIS on low SG pressure	16.4	11.3
MSIVs closed	23.3	18.2
Minimum unaffected sector core inlet temperature	27.0	33.4
HPSI pumps available (RCS pressures higher than the HPSI pump shutoff head)	40.3	58.3
Affected SG main feedwater (MFW) isolation valves closed	76.4	71.3
Non-borated HPSI flow begins (unborated water being cleared from the SI lines)	~100.0	---
AFW flow begins (both SGs)	170.0	170.0
Operator terminates AFW. Affected SG mass inventory begins to decrease.	---	600.0
Shutdown worth has been fully overcome by moderator and Doppler feedback	233.0	695.0
Operator terminates AFW. Affected SG mass inventory begins to decrease.	600.0	---
Peak post-scram reactor power	602.0	2412.0
MDNBR	602.0	2412.0
Maximum LHR	602.0	2412.0

Table 2.8.5.1.2-5
Post-Scram Main Steam Line Break
Results and Comparison to Previous Results

Case	Criterion	Previous Analysis	EPU Analysis	Limit
HFP, Offsite Power Available	MDNBR (%fuel failure)	4.541 (0)	2.732 (0)	≥ 1.158
	Peak LHR, kW/ft (%fuel failure)	12.6 (0)	21.102 (0)	≤ 22.279
HFP, Loss of Offsite Power	MDNBR (%fuel failure)	6.232 (0)	3.290 (0)	≥ 1.158
	Peak LHR, kW/ft (%fuel failure)	3.8 (0)	7.044 (0)	≤ 22.279
HZP, Offsite Power Available	MDNBR (%fuel failure)	4.755 (0)	2.431 (0)	≥ 1.158
	Peak LHR, kW/ft (%fuel failure)	11.9 (0)	23.342 (0.02)	(1)
HZP, Loss of Offsite Power	MDNBR (%fuel failure)	6.119 (0)	1.282 (0)	≥ 1.158
	Peak LHR, kW/ft (%fuel failure)	3.8 (0)	12.788 (0)	≤ 22.279

1. The FCM limit of 22.279 kW/ft is the calculated limit to preclude fuel centerline melt across all fuel types. In the HZP Post-trip MSLB case, an evaluation was performed on a pin type specific basis to determine the amount of fuel failure predicted for the event.

Figure 2.8.5.1.2-1
Pre-Scram Main Steam Line Break
Reactor Power

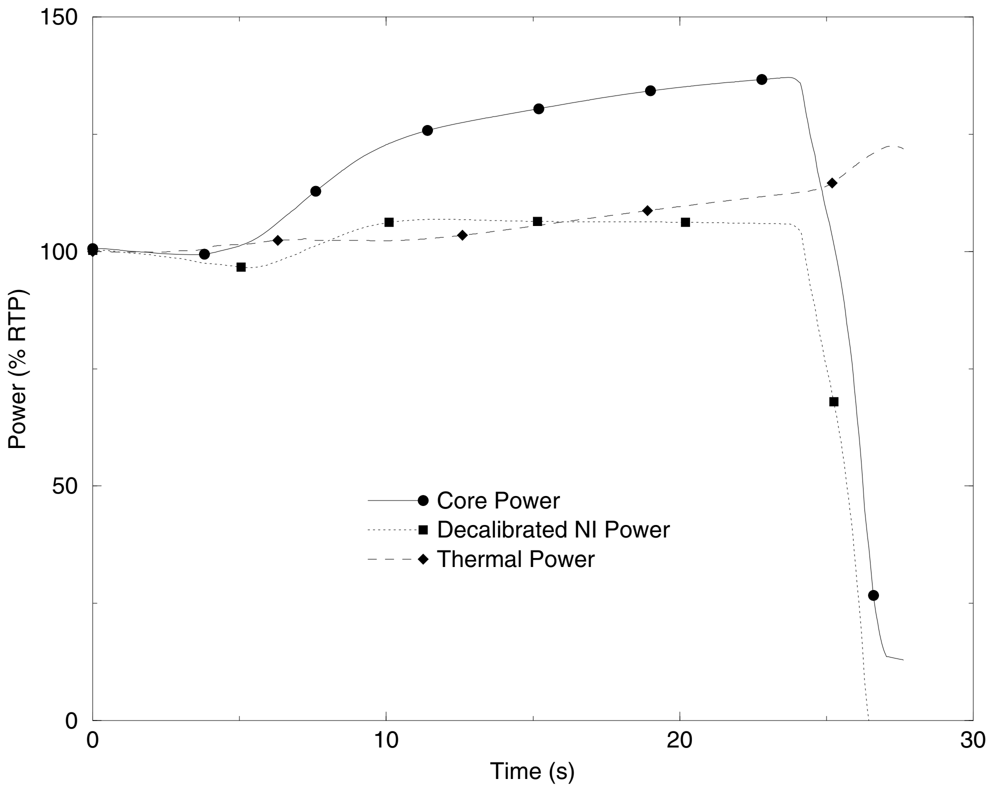


Figure 2.8.5.1.2-2
Pre-Scram Main Steam Line Break
Total Core Heat Flux Power

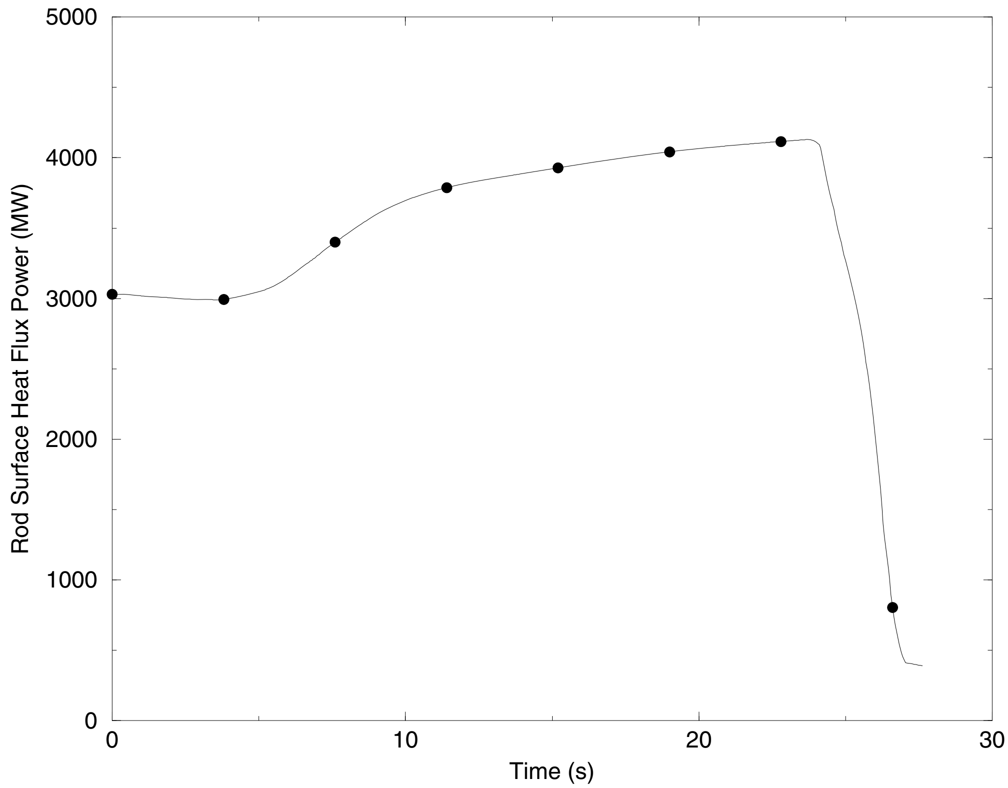


Figure 2.8.5.1.2-3
Pre-Scram Main Steam Line Break
Pressurizer Pressure

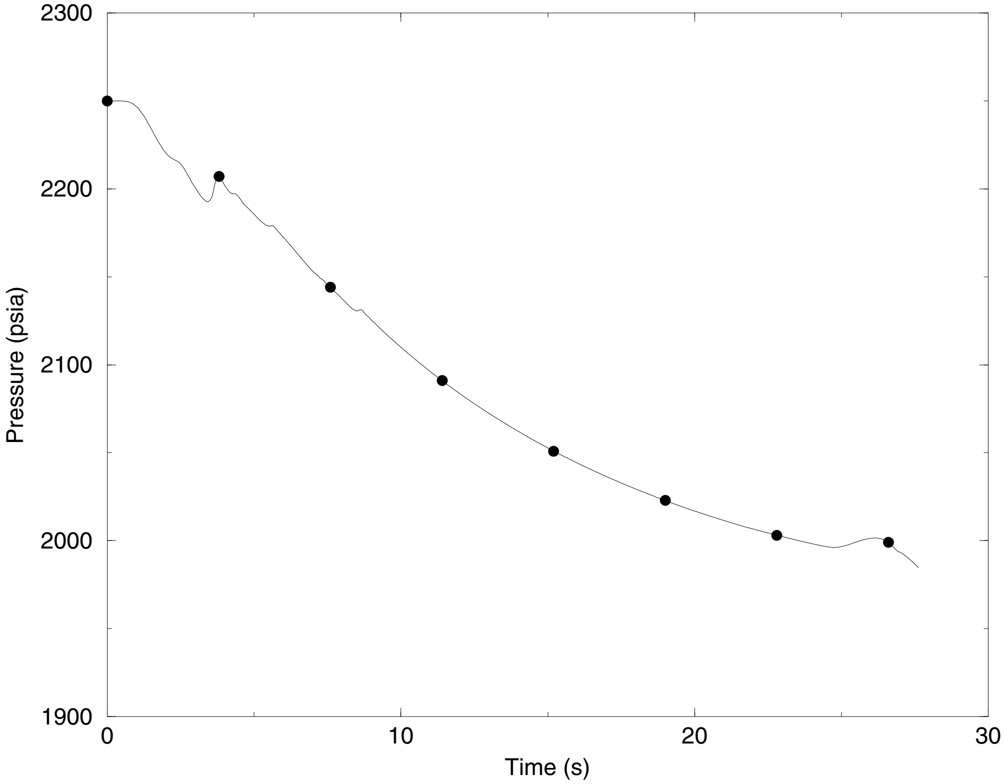


Figure 2.8.5.1.2-4
Pre-Scram Main Steam Line Break
Pressurizer Liquid Level

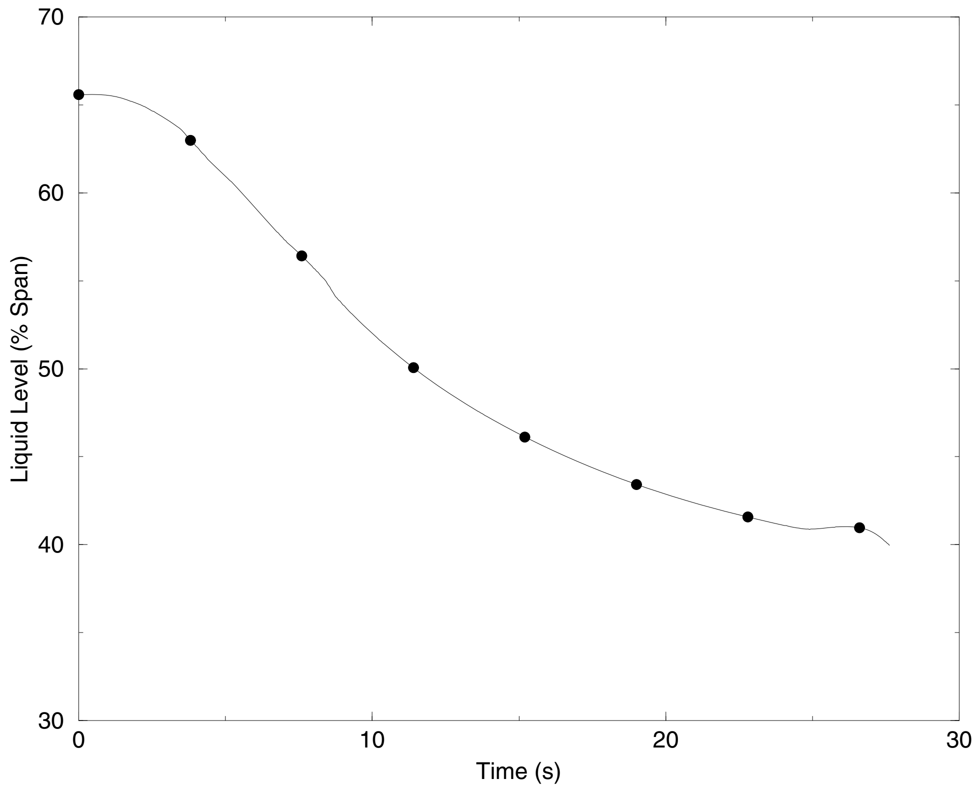


Figure 2.8.5.1.2-5
Pre-Scram Main Steam Line Break
RCS Loop Temperatures

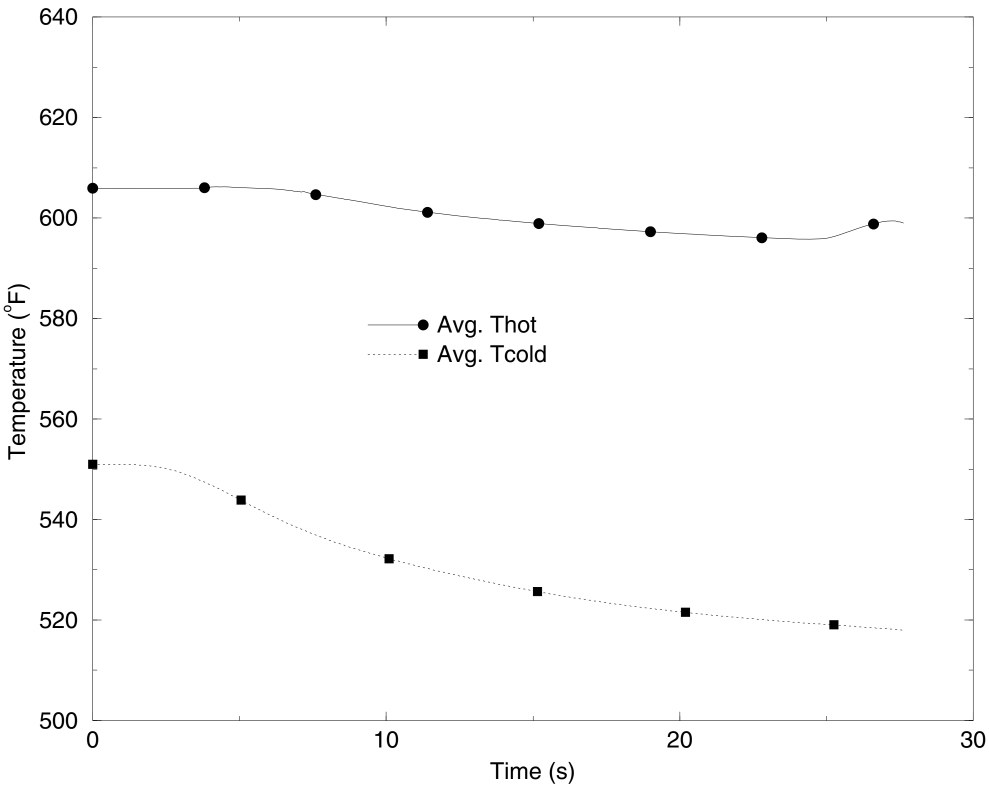


Figure 2.8.5.1.2-6
Pre-Scram Main Steam Line Break
RCS Total Loop Flow Rate

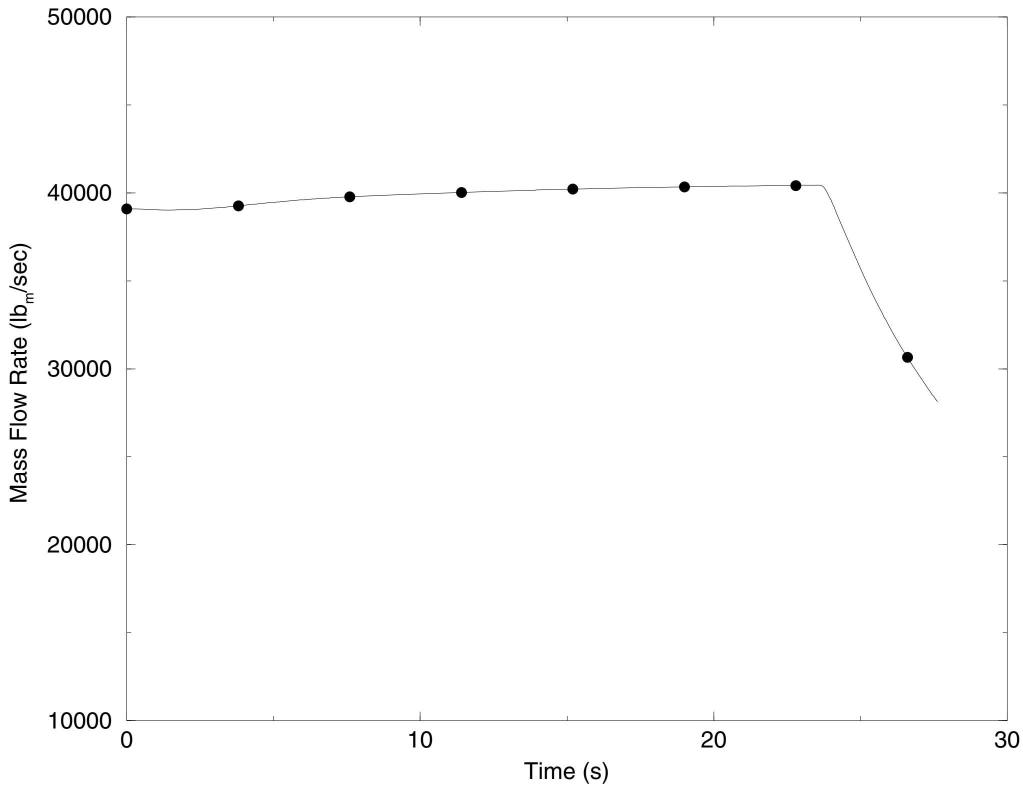


Figure 2.8.5.1.2-7
Pre-Scram Main Steam Line Break
Steam Generator Pressure

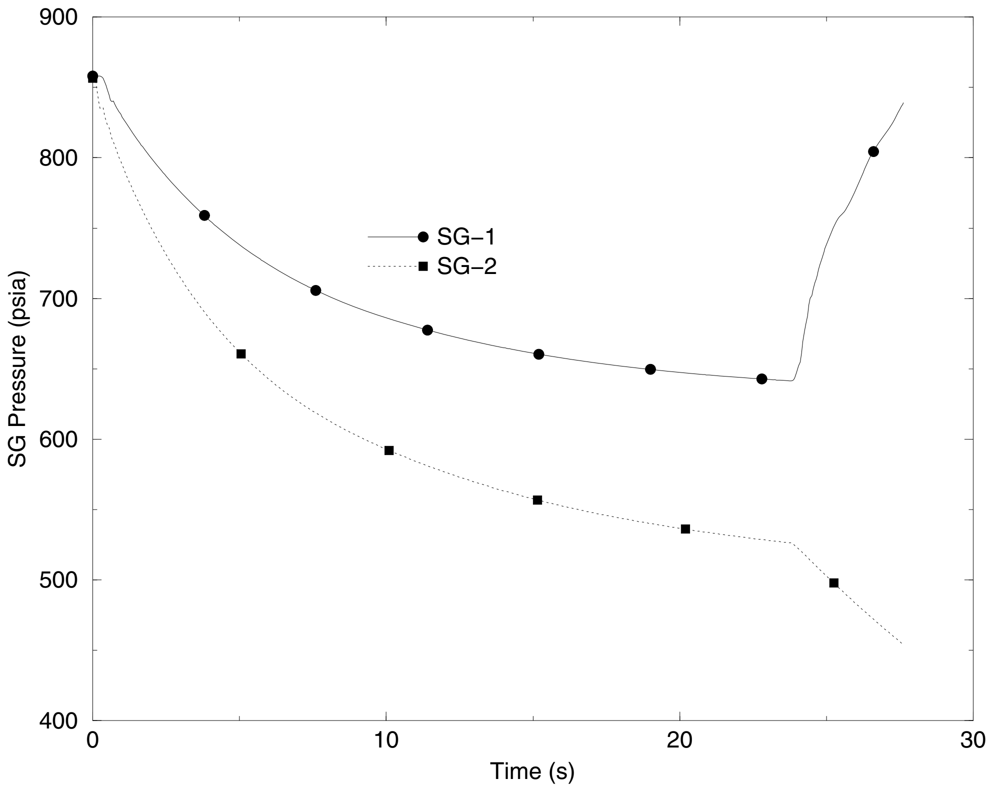


Figure 2.8.5.1.2-8
Pre-Scram Main Steam Line Break
Break Flow Rate

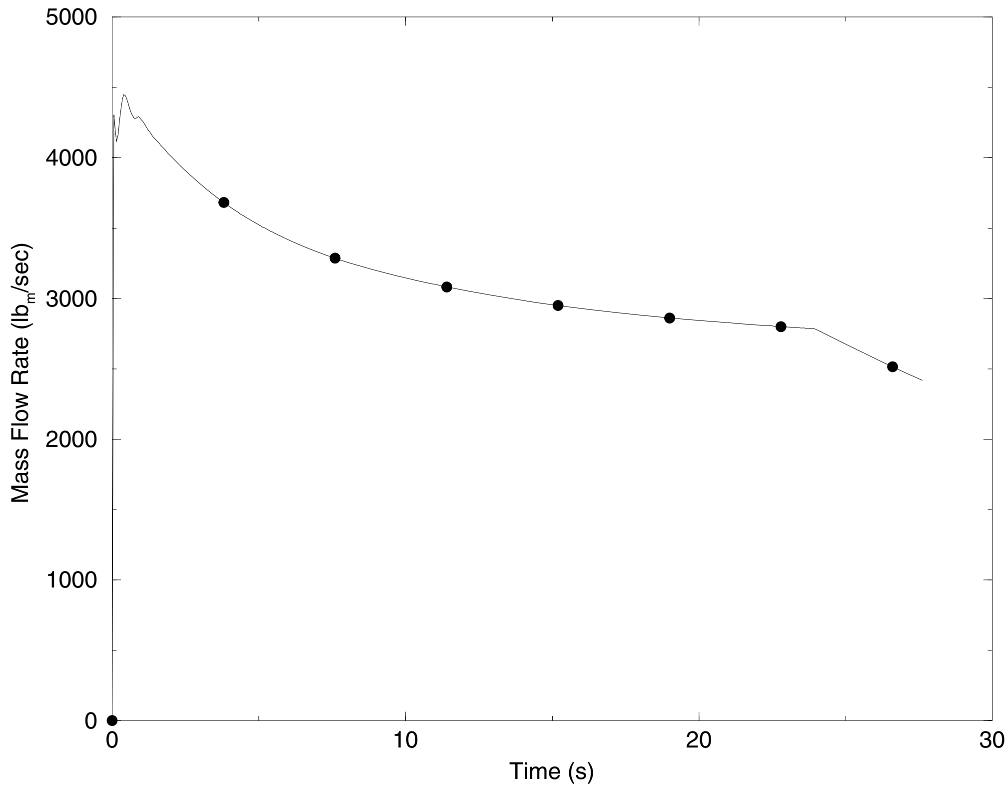


Figure 2.8.5.1.2-9
Pre-Scram Main Steam Line Break
Steam and Feedwater Flow Rates

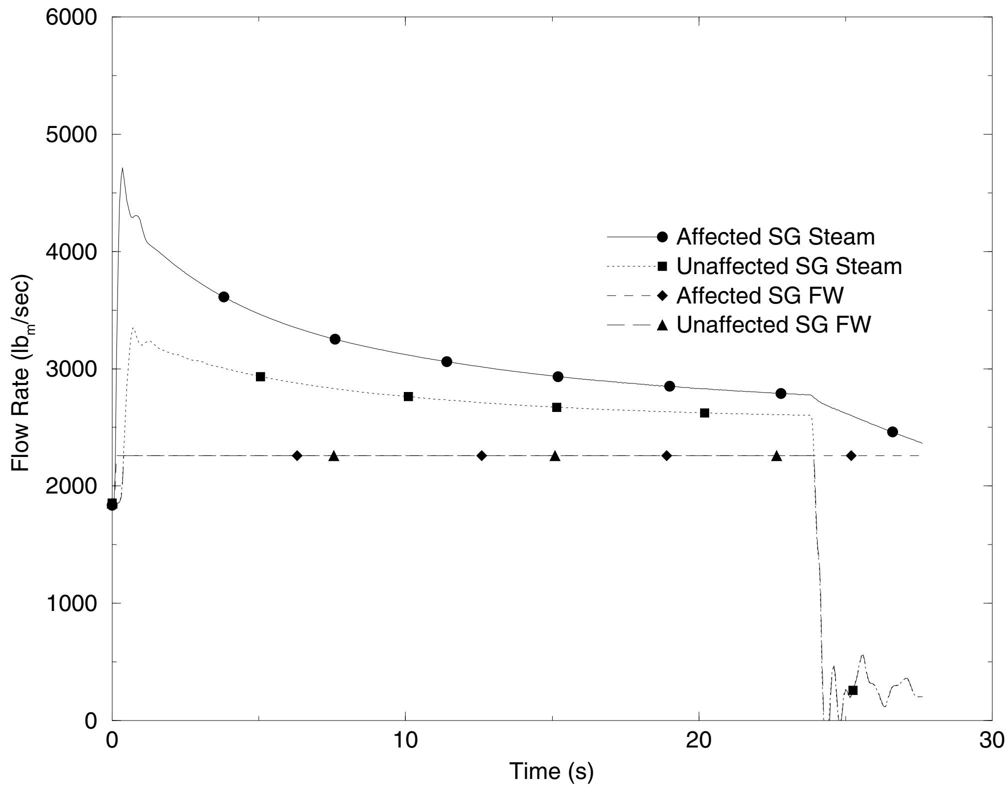


Figure 2.8.5.1.2-10
Pre-Scram Main Steam Line Break
Reactivity Feedback

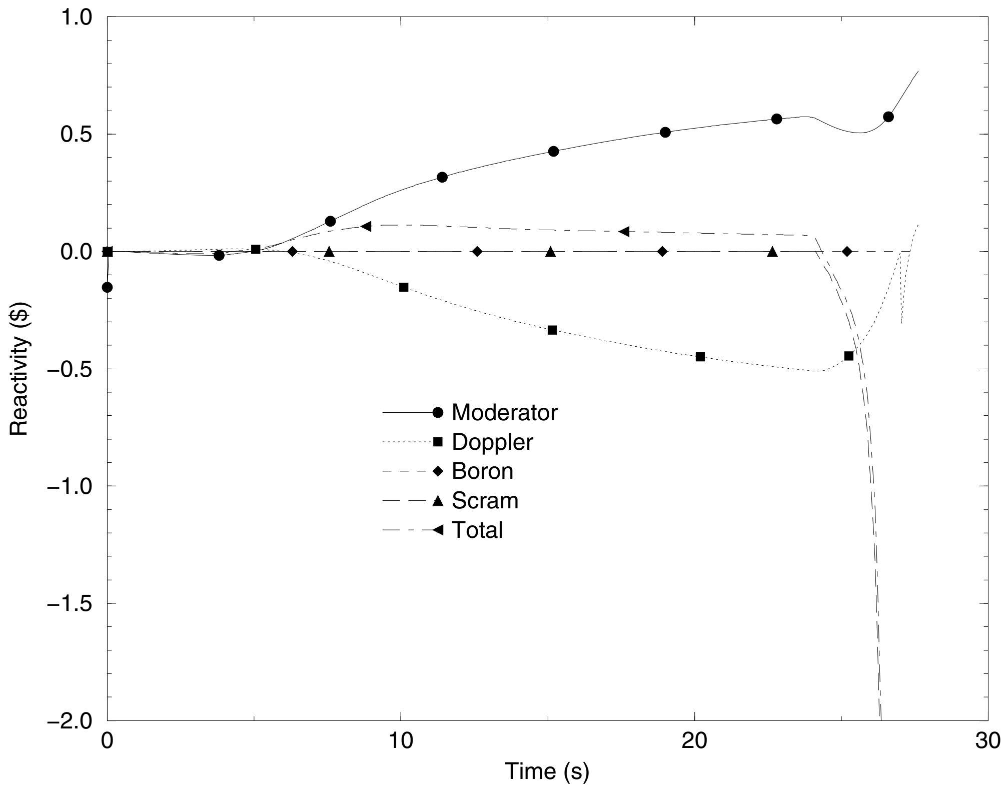


Figure 2.8.5.1.2-11
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Break Flow Rates

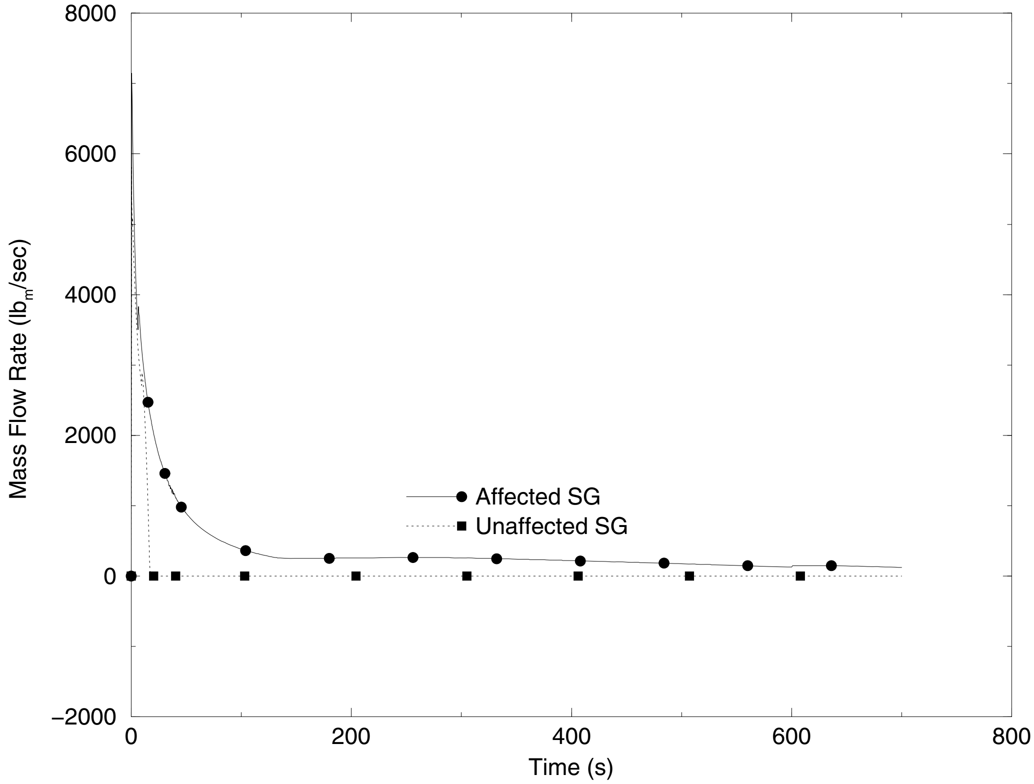


Figure 2.8.5.1.2-12
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Steam Generator Pressures

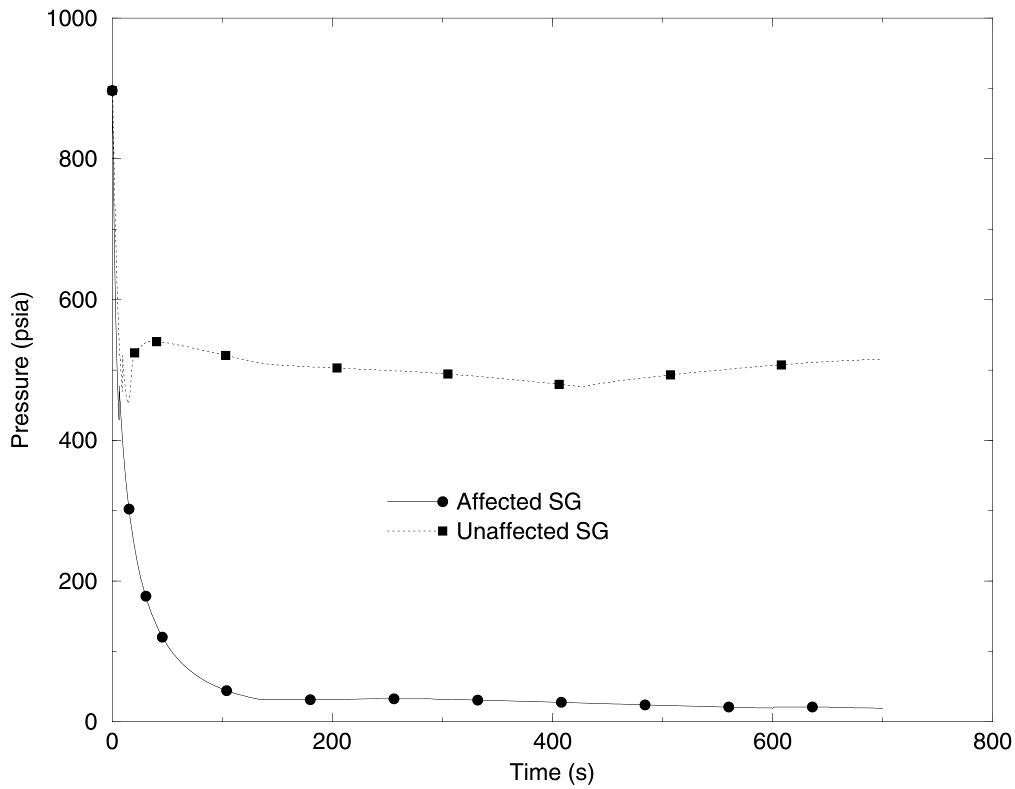


Figure 2.8.5.1.2-13
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Combined MFW and AFW Flow Rates

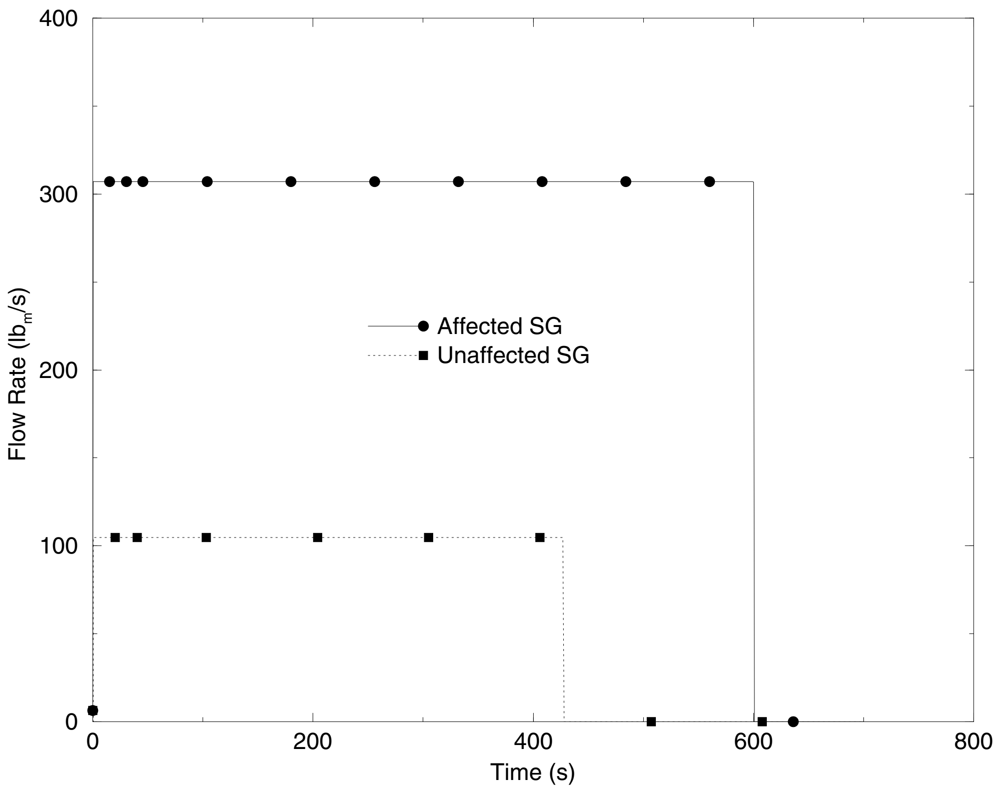


Figure 2.8.5.1.2-14
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Steam Generator Mass Inventories

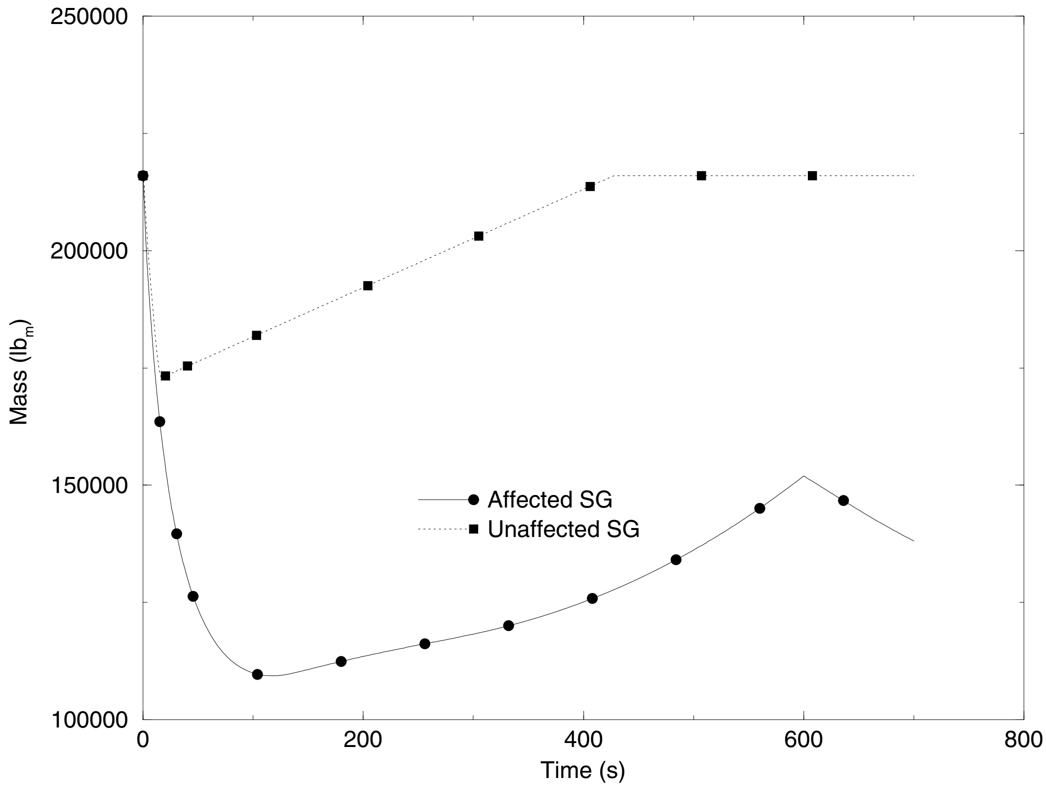


**Figure 2.8.5.1.2-15
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Core Inlet Fluid Temperatures**

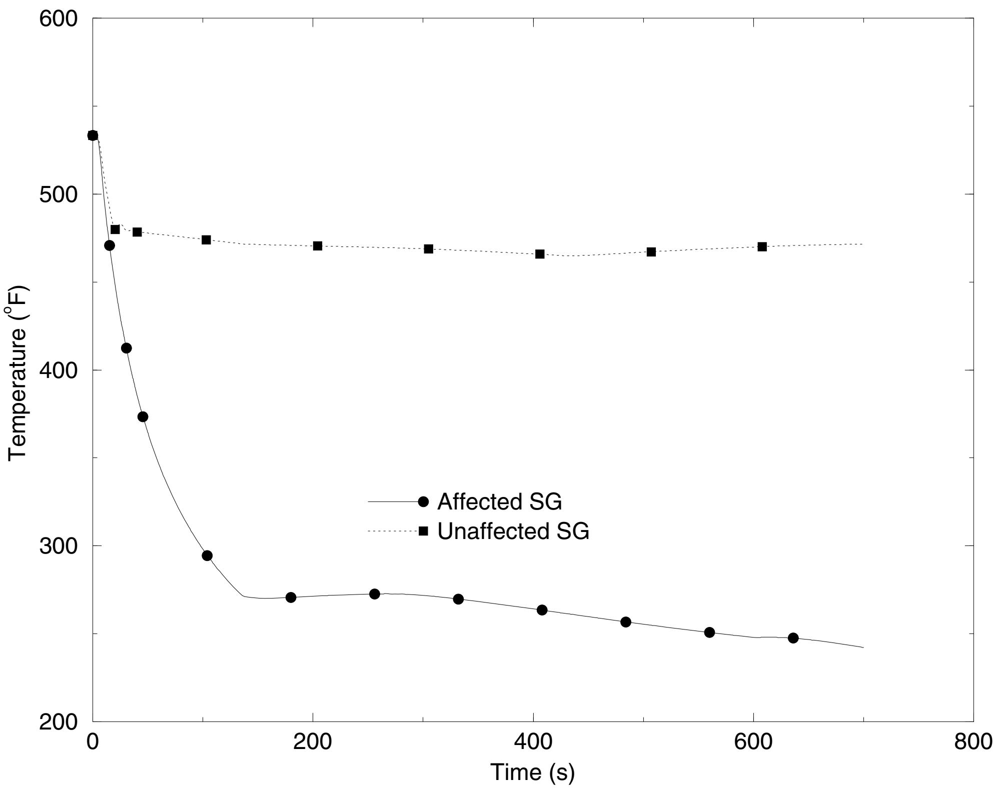


Figure 2.8.5.1.2-16
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Pressurizer Liquid Level

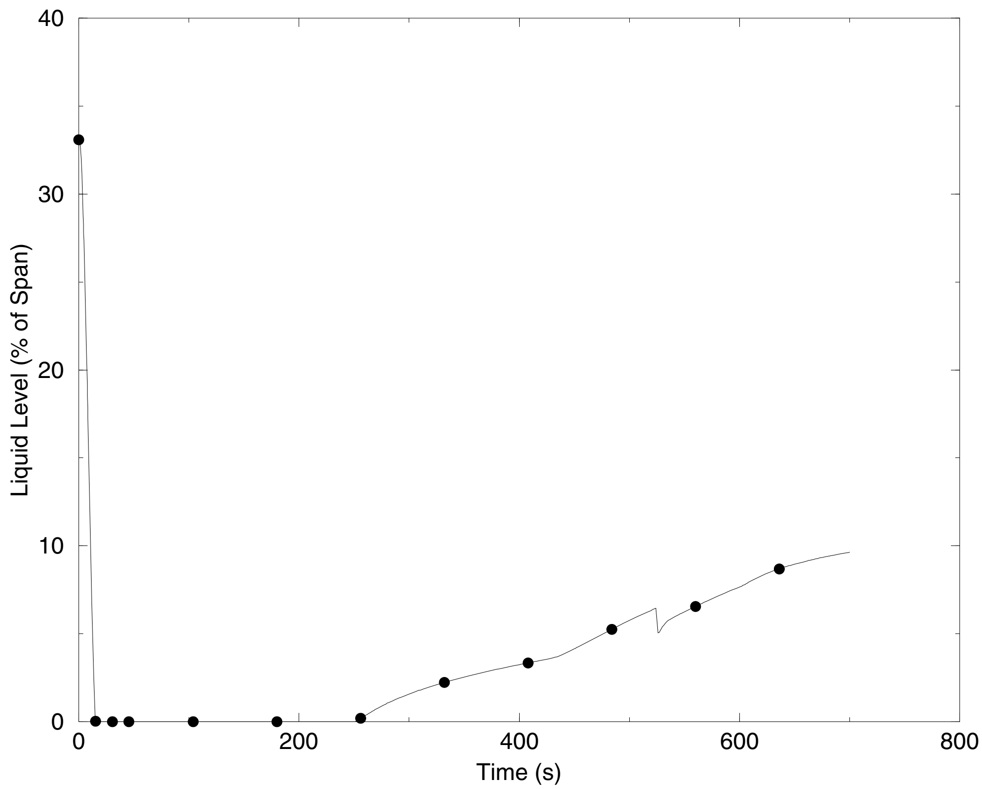


Figure 2.8.5.1.2-17
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Pressurizer Pressure

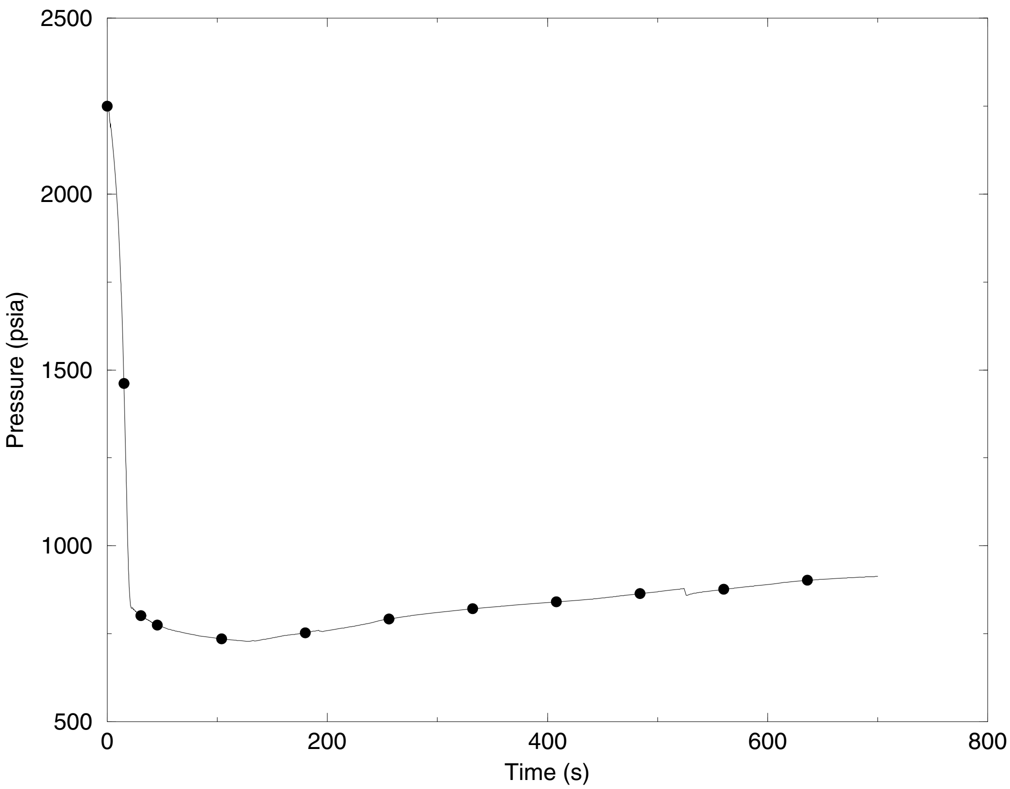


Figure 2.8.5.1.2-18
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Total HPSI Flow Rate

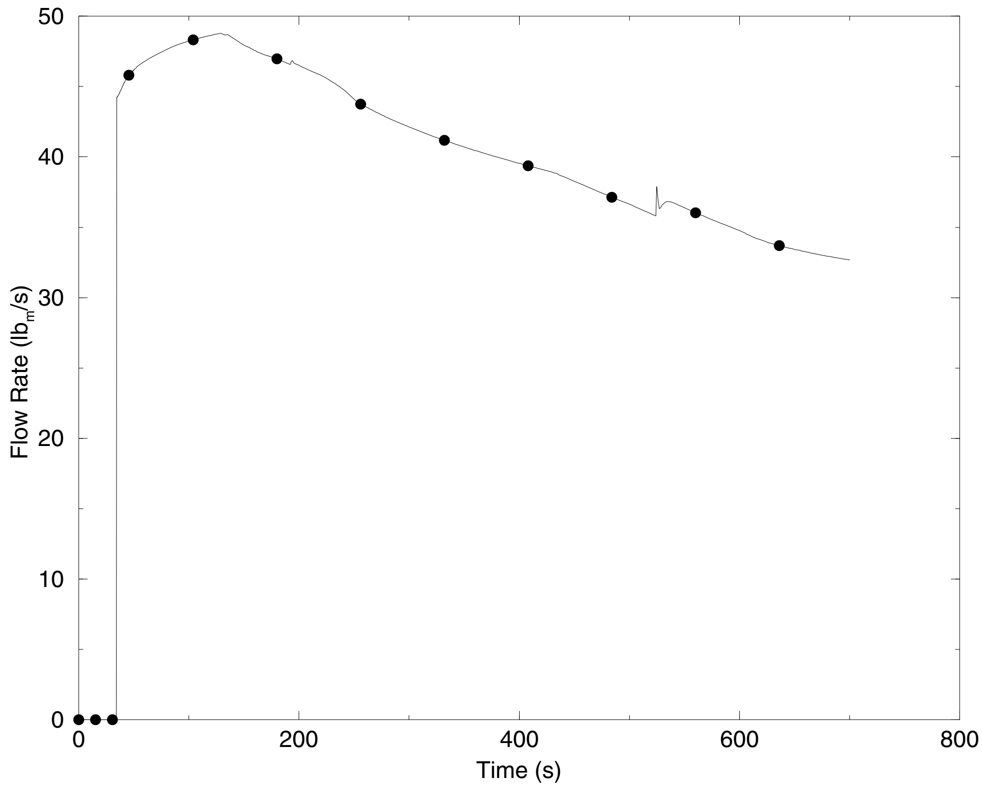


Figure 2.8.5.1.2-19
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Reactivity Feedback

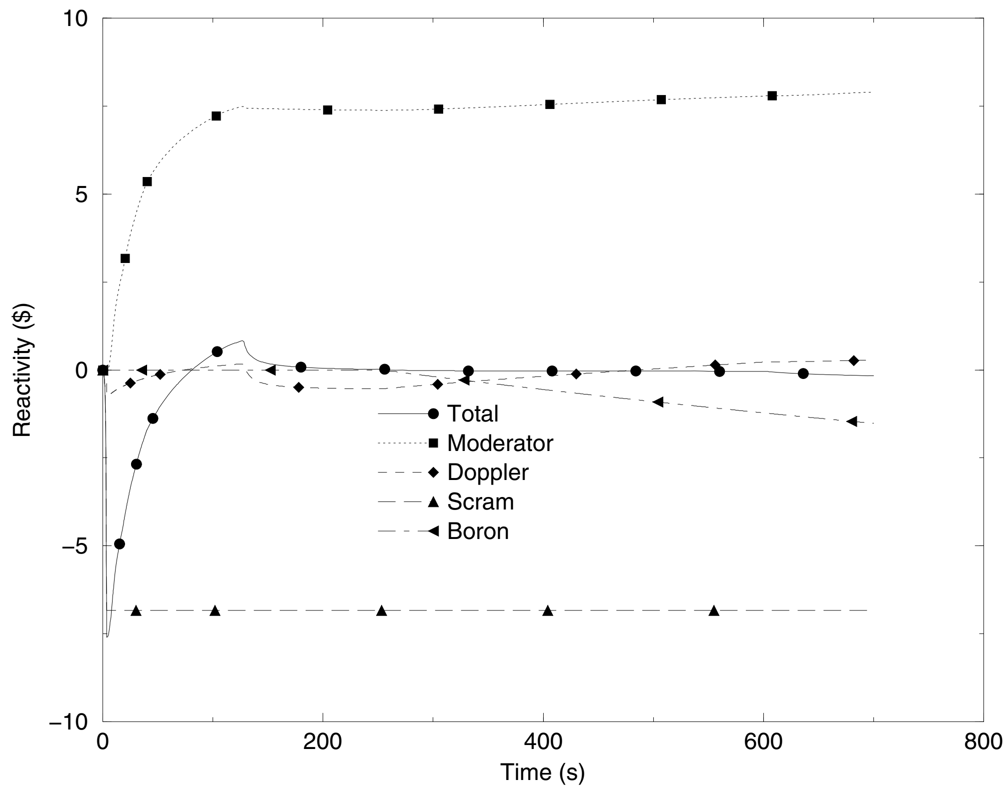


Figure 2.8.5.1.2-20
Post-Scram Main Steam Line Break
(HZP, Offsite Power Available)
Core Power

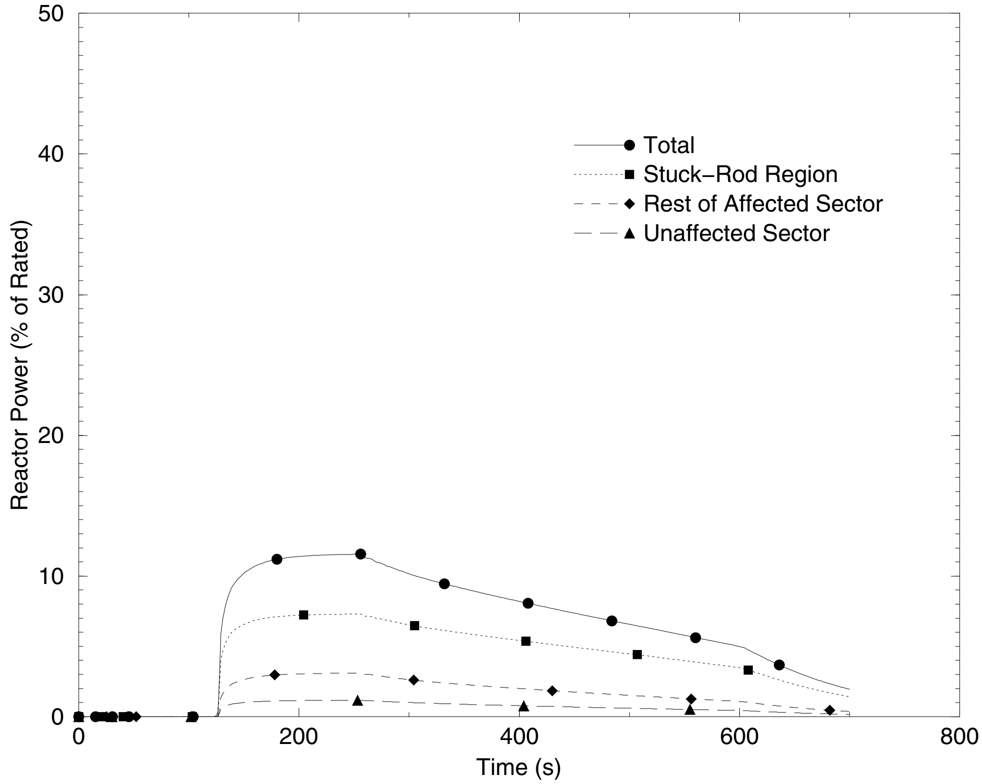


Figure 2.8.5.1.2-21
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Break Flow Rates

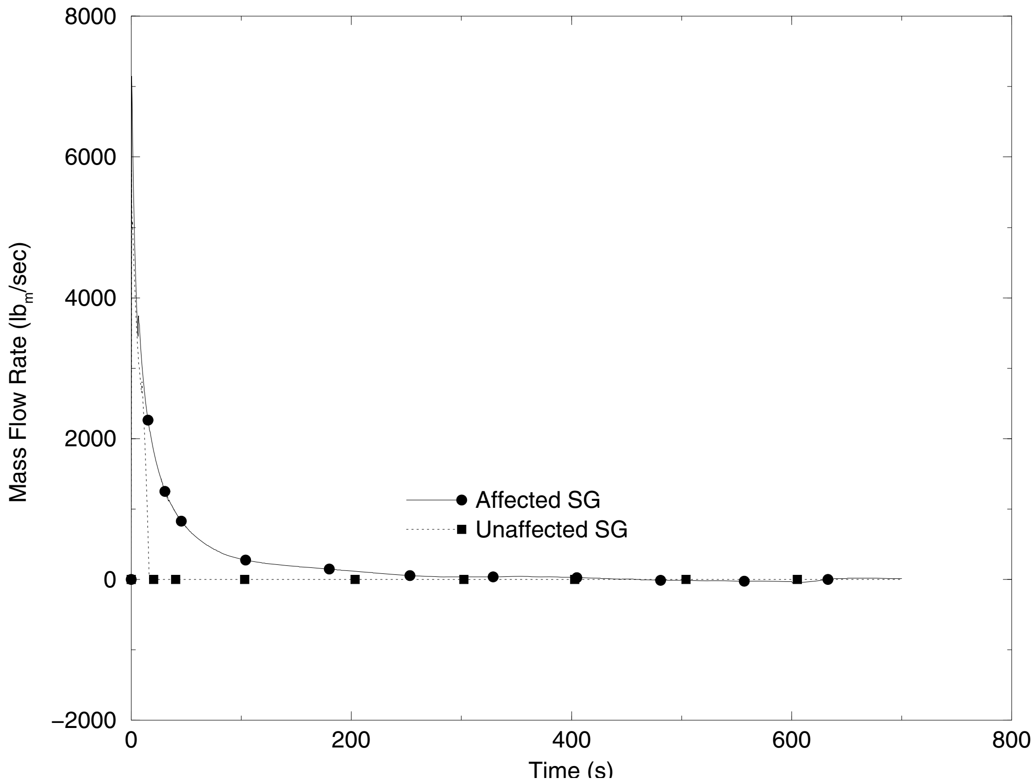


Figure 2.8.5.1.2-22
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Steam Generator Pressures

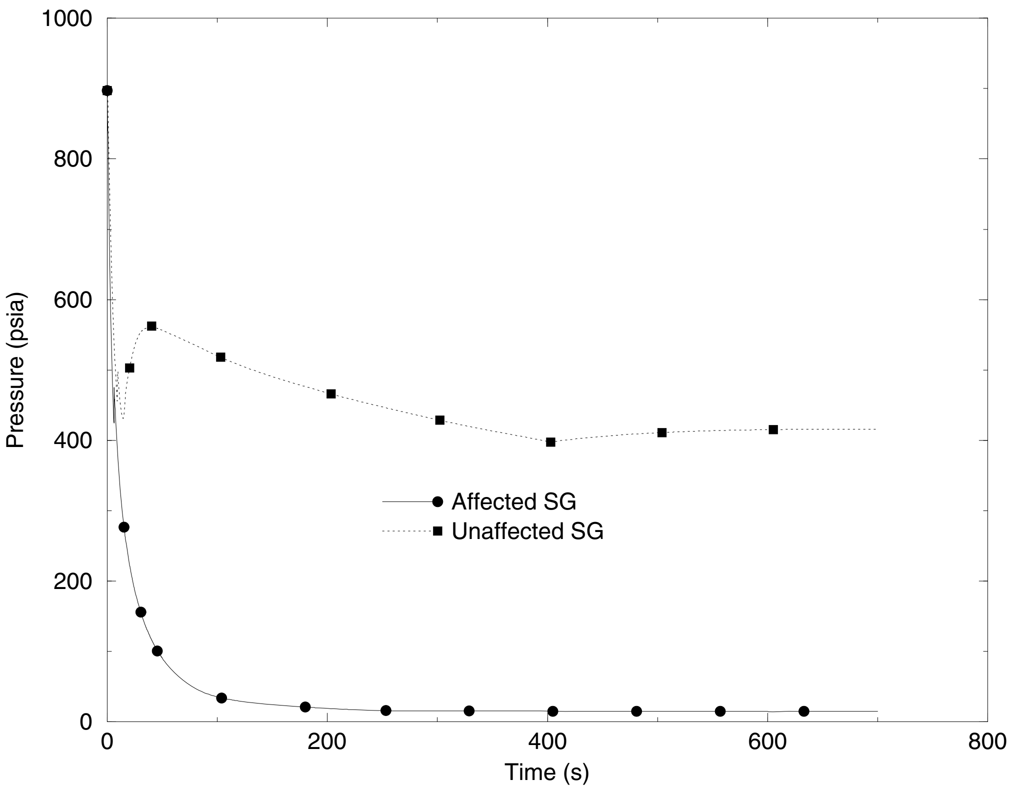


Figure 2.8.5.1.2-23
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Combined MFW and AFW Flow Rates

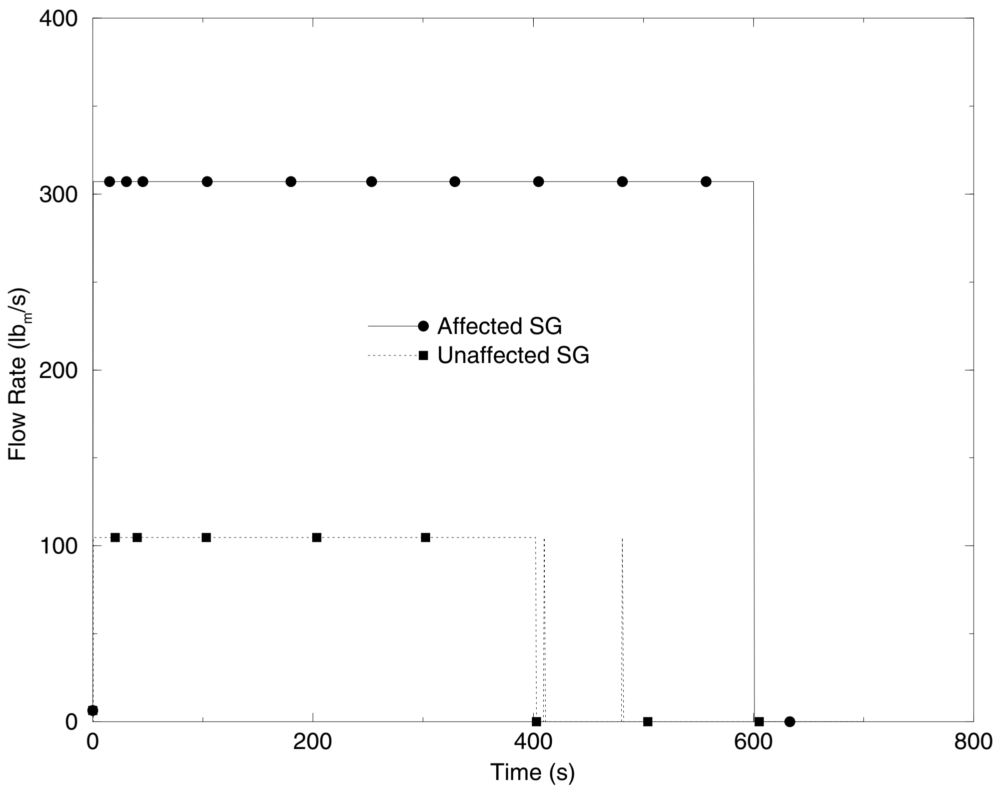


Figure 2.8.5.1.2-24
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Steam Generator Mass Inventories

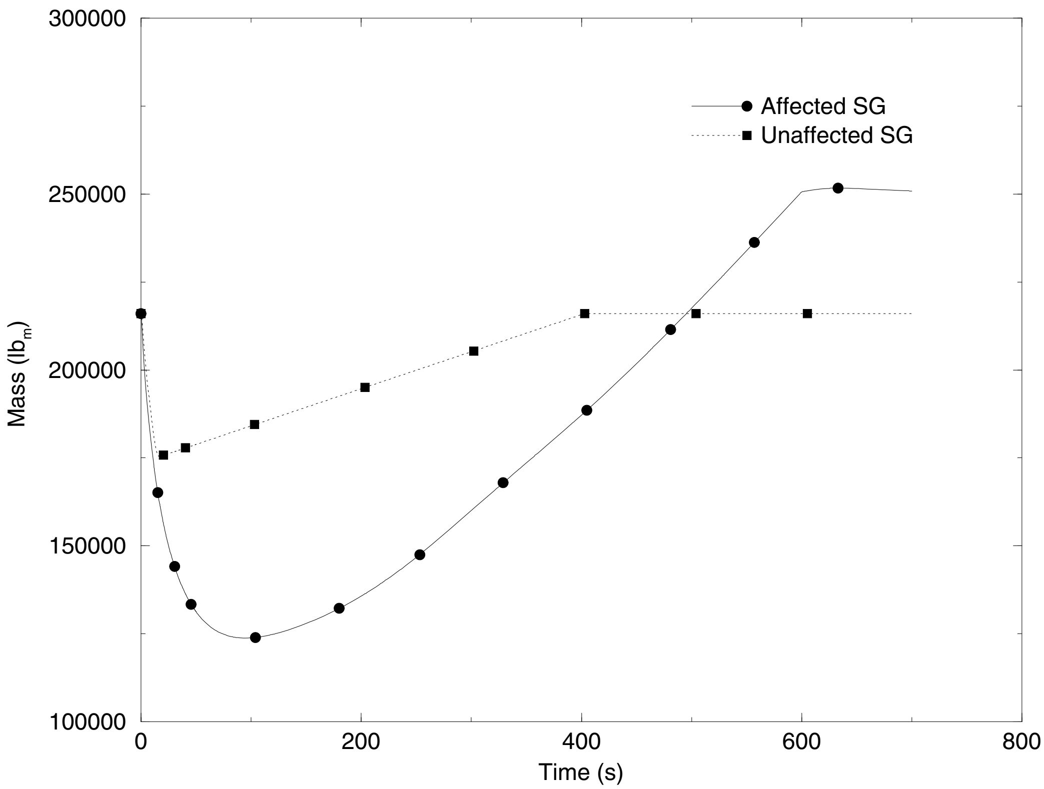


Figure 2.8.5.1.2-25
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Core Inlet Fluid Temperatures

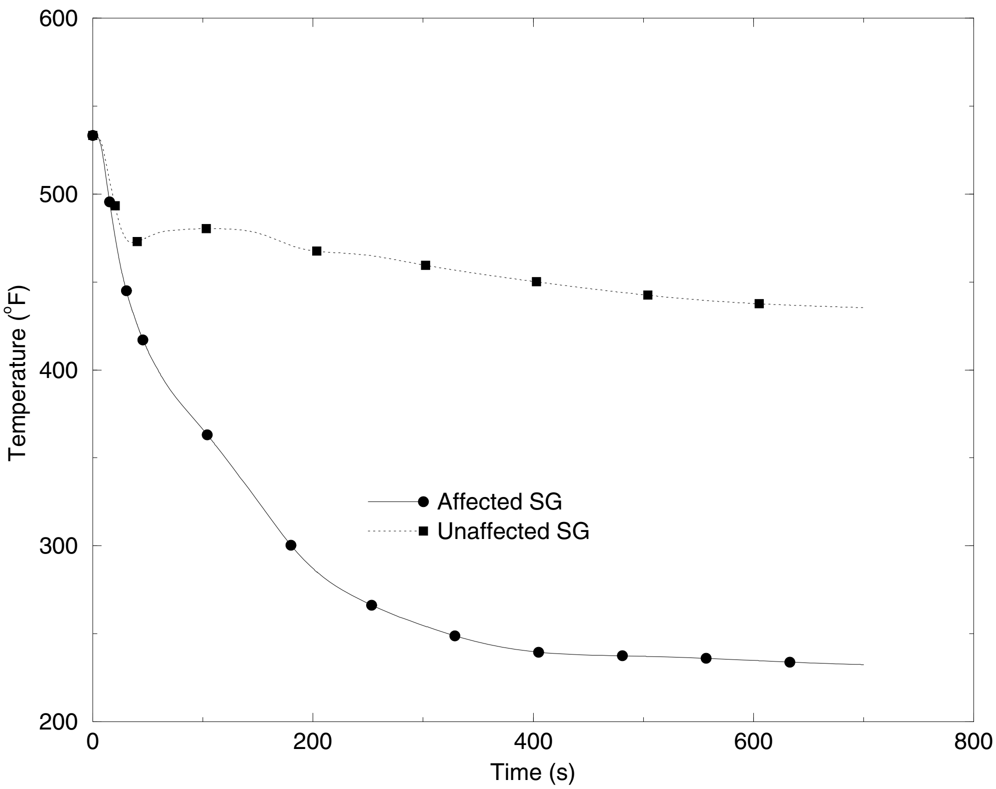


**Figure 2.8.5.1.2-26
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Pressurizer Liquid Level**

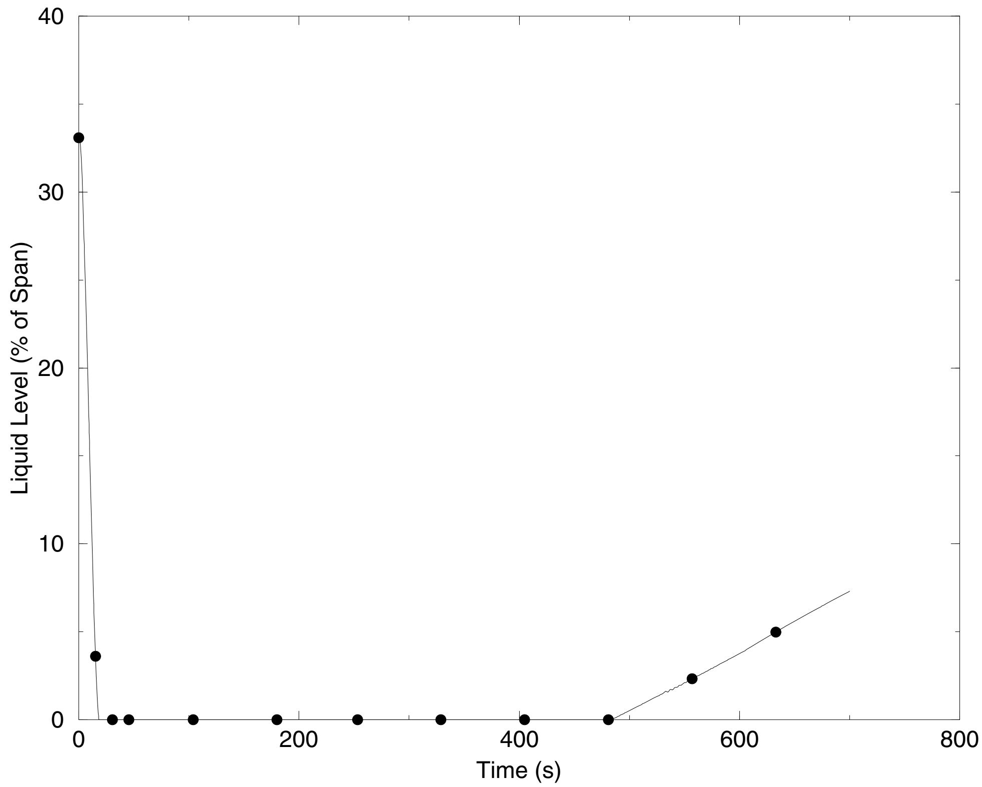


Figure 2.8.5.1.2-27
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Pressurizer Pressure

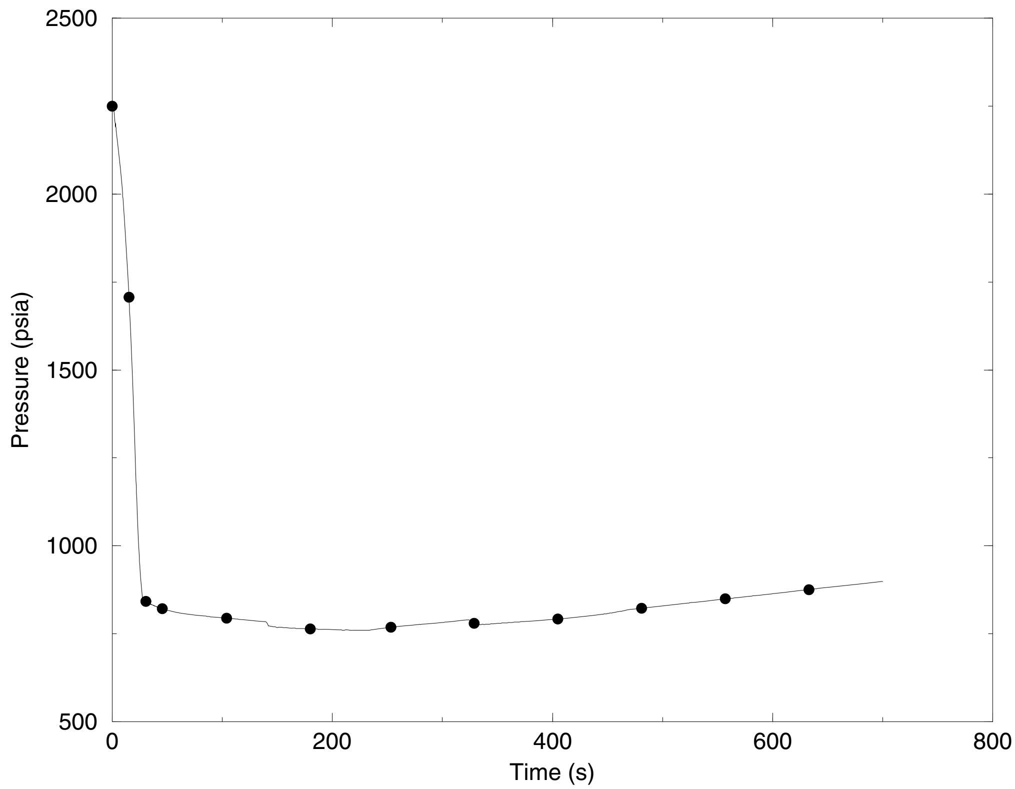


Figure 2.8.5.1.2-28
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Total HPSI Flow Rate

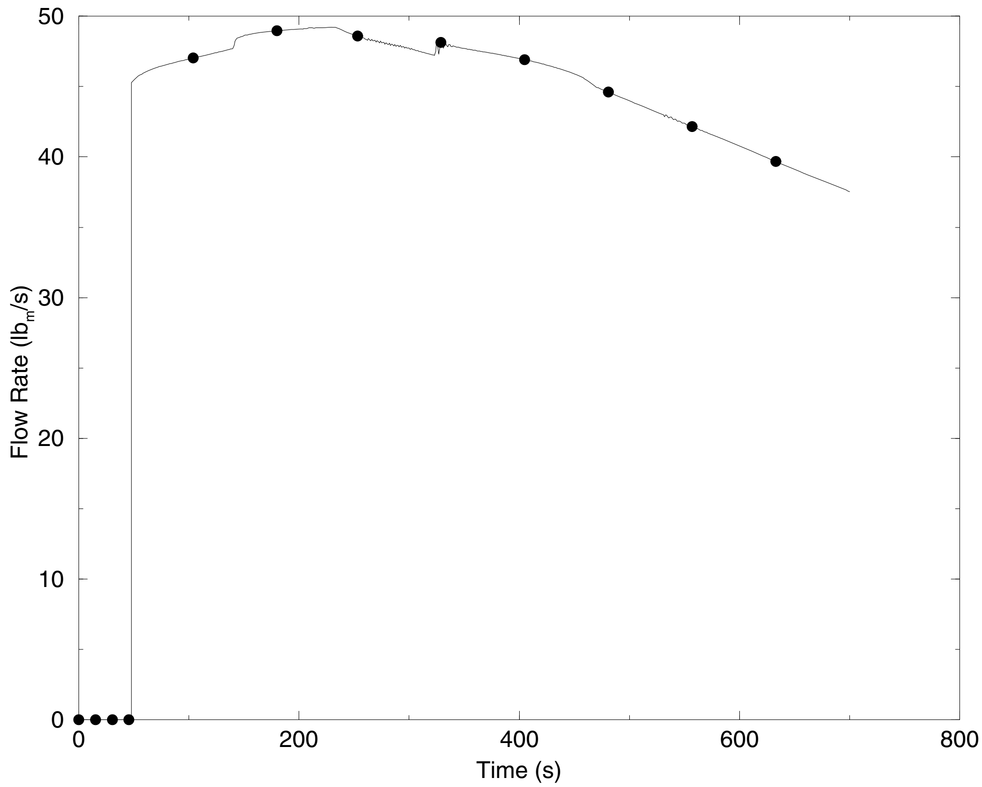


Figure 2.8.5.1.2-29
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Reactivity Feedback

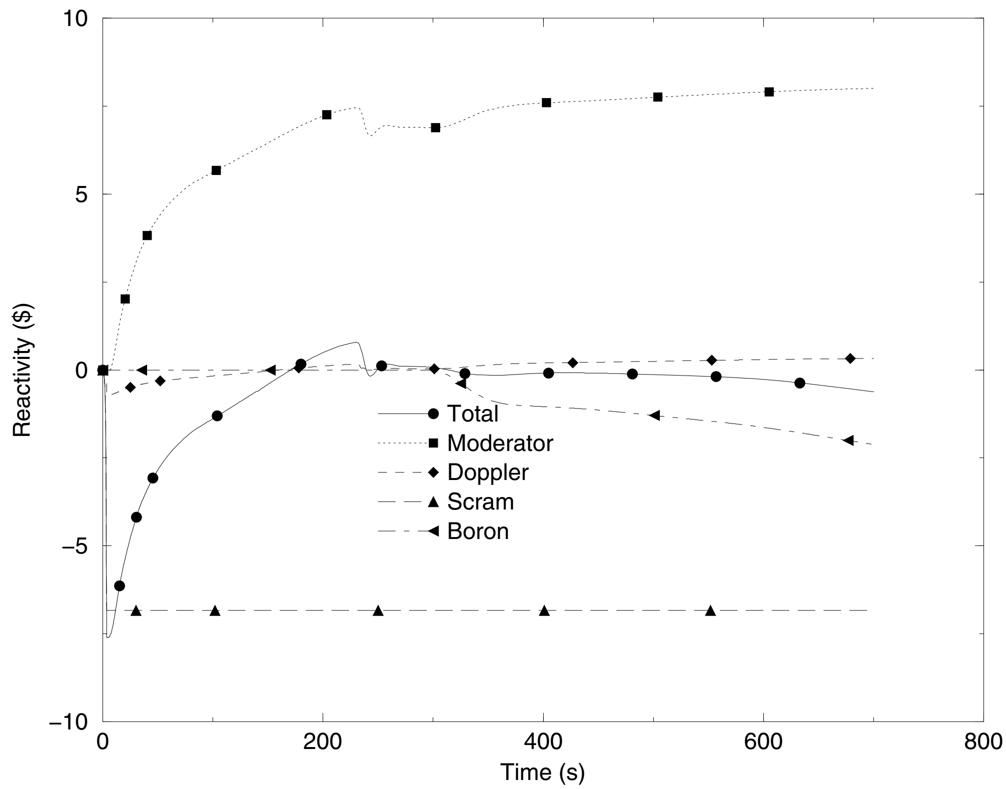
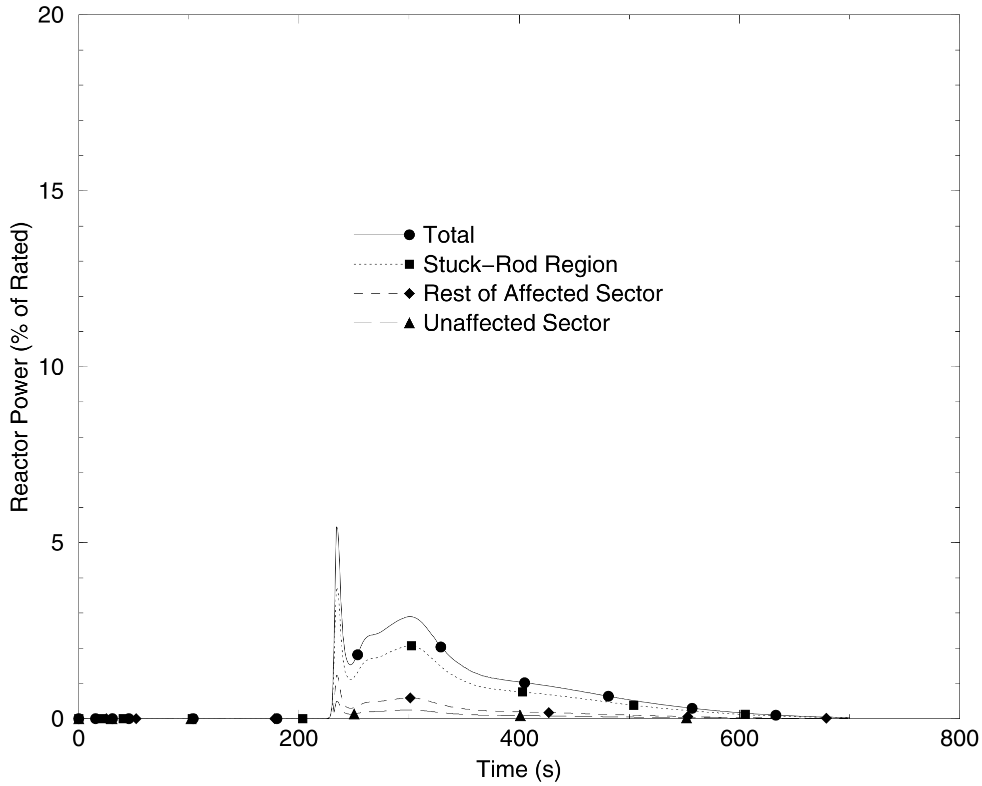


Figure 2.8.5.1.2-30
Post-Scram Main Steam Line Break
(HZP, Loss of Offsite Power)
Core Power



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.

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.

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-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-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the loss of external electrical 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain anticipated operational occurrences; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of 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 control element assemblies (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 AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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 acceptable fuel design limits are not exceeded. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the loss of external electrical load, turbine trip, and loss of condenser vacuum events, as well as the main steam isolation valve (MSIV) closure event, is provided in UFSAR Section 15.2.7.

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.

2.8.5.2.1.2 Technical Evaluation

2.8.5.2.1.2.1 Introduction

A loss of external load event can result due to a loss of external electrical load or a turbine trip. Offsite electrical power is available to operate the reactor coolant pumps (RCPs) and other station auxiliaries. Following the loss of generator load, the turbine control valves close, terminating the steam flow, causing the secondary system temperature and pressure to increase. Primary-to-secondary heat transfer decreases as the secondary system temperature increases.

If the reactor is not tripped when the turbine is tripped, the primary system temperature and pressure will continue to rise. If this continues, the reactor will trip on high pressurizer pressure, reducing the primary heat source. As the heat load into the primary decreases, the primary system pressurization will begin to diminish. If the setpoint for opening the pressurizer safety valves (PSVs) is exceeded during the initial system over-pressurization, these valves will open to relieve pressure and to mitigate the pressure transient. Energy is removed during the early phase of the transient through the steam generator (SG) safety valves, when the SG pressure exceeds the safety valve opening setpoint.

The main purpose of analyzing this event is to demonstrate that the primary and secondary pressure relief capability is sufficient to limit the pressures to less than 110% of their respective design values. This event is also analyzed to ensure that the SAFDLs are not exceeded under the limiting assumptions of no credit for a direct reactor trip on turbine trip.

This event bounds the following events under this category:

Turbine Trip

A turbine trip event is similar to the loss of external load event, but is initiated by trip of the turbine. The assumption of turbine stop valve closure without concurrent reactor trip in the loss of external load event bounds the turbine trip event since reactor trip on turbine trip would be expected. The loss of external load event analysis disables the reactor trip on turbine trip in favor of the high pressure trip (which would occur much later). The turbine trip event is thus bounded by the loss of external load event.

Loss of Condenser Vacuum

A loss of condenser vacuum event is also similar to the loss of external load event, but is initiated by the loss of condenser vacuum. The loss of condenser vacuum disables steam bypass and results in a gradual decrease in steam flow, compared to that resulting from the stop valve closure. Since stop valve closure is assumed for the loss of external load event, this event is bounded by the loss of external load event.

Closure of Main Steam Isolation Valve

A closure of MSIV event postulates that one or both of the MSIVs close to initiate the event. The closure of both the MSIVs is not worse than the closure of the turbine stop valves on a turbine trip. The more rapid closure of the turbine stop valves produces a more severe system transient than does the closure of both MSIVs. Closure of both MSIVs is thus bounded by the loss of external load event.

The evaluation of a closure of a single MSIV is provided in LR Section 2.8.5.2.5, Asymmetric Steam Generator Transient.

2.8.5.2.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of the loss of external load event are consistent with the approved Reference 3 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions - This event was analyzed from hot full power (HFP) since the resultant loss of steam load was the greatest and presented the most significant challenge to the safety valve performance for primary system pressure and for secondary system pressure with all main steam safety valves (MSSVs) operable. In addition, for the minimum departure from nucleate boiling ratio (MDNBR) case, assuming a HFP initial condition with a maximum core inlet temperature and TS minimum RCS flow minimized the initial margin to departure from nucleate boiling (DNB).

  For the part-power cases, the secondary side peak pressure was calculated for one, two and three out-of-service MSSVs per steam line. The current TS Table 3.7-1 allowed variable high power trip (VHPT) setpoints were validated as a function of the number of out-of-service MSSVs, based on maintaining the peak secondary side pressure to less than 110% of design.

- Reactivity Feedback – Beginning of cycle (BOC) kinetics parameters were biased to maximize the increase in reactor power during the transient. In general, the reactivity feedback was not significant for this event.

- Reactor Protection System (RPS) Trips and Delays - This event was analyzed without a direct reactor trip from the turbine trip. This assumption conservatively delayed reactor trip until conditions in the RCS resulted in a high pressurizer pressure trip. RPS trip setpoints were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion was delayed to account for the CEA holding coil delay time.

- Pressurizer Pressure Control - Pressurizer pressure control (i.e., pressurizer sprays, heaters and power operated relief valves) was treated differently among the various cases. For the primary side overpressure case, the parameters and equipment operational states were selected to maximize the primary system pressure. For the secondary side pressure case, the parameters and equipment operational states were selected to maximize the secondary system pressure. For the MDNBR case, the parameters and equipment states were selected to reduce the primary system pressure which provided a conservative calculation of the MDNBR during the transient.
- Pressurizer and Main Steam Safety Valves – For the cases that evaluated peak primary and secondary system pressures, the PSVs and MSSVs were conservatively modeled. The PSVs and MSSVs as-left setpoints are unchanged from the current TS value ±1%. The as-found setpoint tolerance limits for the PSVs are also unchanged from the current TS values. The as-found setpoint tolerance (on the positive side) for the MSSVs is, however, being changed to +3% for the first bank of valves and +2% for the second bank of valves, as identified in the LAR Attachment 1 description of TS changes. The opening setpoints of the safety valves, in the overpressurization analyses, were biased high to the TS upper tolerance limits.
- Gap Conductance – Gap conductance was set to a conservative BOC value to be consistent with the time-in-cycle for the reactivity coefficients.
- Steam Generator Tube Plugging (SGTP) – Both minimum (0%) and maximum (10%) SGTP were considered depending on the acceptance criterion being evaluated (i.e., primary system overpressure, secondary system overpressure, and MDNBR).
- Single Failure - No single active failure will prevent operation of any system required to function for this event.

The acceptance criteria for this event are:

- The pressures in the RCS and main steam system should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

Peak primary and secondary side pressures are calculated to verify that pressure limits are met. For the SAFDLs, this criterion is met by assuring that the minimum calculated DNBR is not less than the 95/95 DNB correlation limit. Since this event does not involve a significant power transient or augmented peaking, the fuel centerline melt limit is not challenged.

2.8.5.2.1.2.3 Description of Analyses and Evaluations

The analyses supporting current plant operation were performed with the non-LOCA methodologies based on the PTSPWR2 code (Reference 1) and the ANF-RELAP code (Reference 2). For the EPU, detailed analyses were performed with the approved non-LOCA methodology given in Reference 3. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), an estimated time of MDNBR and peak system pressures. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 4), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 5).

Three cases were analyzed from a HFP initial condition to assess the challenge to acceptance criteria: (1) primary side pressure, (2) secondary side pressure, and (3) MDNBR. In addition, part-power cases were analyzed to assess the impact to secondary side pressures due to varying number of MSSVs being out-of-service to provide the basis for TS 3/4.7.1.1.

2.8.5.2.1.2.4 Evaluation of 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

2.8.5.2.1.2.5 Results

Primary Side Pressure

The sequence of events is given in LR Table 2.8.5.2.1-1. Results are given in LR Table 2.8.5.2.1-2, which also provides a comparison to the results from the previous analyses. The peak RCS pressure is less than 110% of design (i.e., 2750 psia).

The transient response is shown in LR Figures 2.8.5.2.1-1 through 2.8.5.2.1-10. LR Figure 2.8.5.2.1-1 shows the reactor power as a function of time. LR Figures 2.8.5.2.1-2 through 2.8.5.2.1-10 show the pressurizer pressure, the pressurizer liquid level, the PSV flow rate, the RCS loop temperatures, the total RCS flow rate, the SG pressures, the MSSV flow rates, the reactivity feedback, and the peak RCS pressure, respectively.

Secondary Side Pressure

The sequence of events is given in LR Table 2.8.5.2.1-1. Results are given in LR Table 2.8.5.2.1-2, which also provides a comparison to the results from the previous analyses. The peak secondary side pressure is less than 110% of design (i.e., 1100 psia).

The transient response is shown in LR Figures 2.8.5.2.1-11 through 2.8.5.2.1-19. LR Figure 2.8.5.2.1-11 shows the reactor power as a function of time. LR Figures 2.8.5.2.1-12 through 2.8.5.2.1-19 show the pressurizer pressure, the pressurizer liquid level, the RCS loop temperatures, the total RCS flow rate, the SG pressures, the MSSV flow rates, the reactivity feedback, and the peak secondary system pressure, respectively.

For the part-power cases with one, two and three MSSVs out-of-service per SG, the calculated peak secondary side pressures were calculated to be less than 110% of design (i.e., 1100 psia) as shown in LR Table 2.8.5.2.1-3. The TS allowed VHPT setpoints currently in TS 3/4.7.1.1 were validated.

MDNBR

The sequence of events is given in LR Table 2.8.5.2.1-1. Results are given in LR Table 2.8.5.2.1-2. The MDNBR is greater than the 95/95 limit.

The transient response is shown in LR Figures 2.8.5.2.1-20 through 2.8.5.2.1-28. LR Figure 2.8.5.2.1-20 shows the reactor power as a function of time and LR Figure 2.8.5.2.1-21 shows the reactor power based on rod surface heat flux as a function of time. LR Figures 2.8.5.2.1-22 through 2.8.5.2.1-28 show the pressurizer pressure, the pressurizer liquid level, the pressurizer PORV flow rate, the RCS loop temperatures, the total RCS flow rate, the SG pressures, and the reactivity feedback, respectively.

2.8.5.2.1.3 Conclusion

FPL has performed the analyses of 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 analyses has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary 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 Extended Power Uprate (EPU). Therefore, FPL finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.1.4 References

1. ANF-84-73(P)(A), Revision 5, Appendix B, & Supplements 1 and 2, Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events, Advanced Nuclear Fuels Corporation, October 1990.

2. ANF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

3. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

4. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

5. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.2.1-1
Loss of External Load Sequence of Events

Case	Event	Time (sec)
Primary Side Overpressure (T_{IN} = 535°F)	Turbine trip	0.0
	High Pressurizer Pressure trip setpoint reached	5.1
	Reactor trip occurred on High Pressurizer Pressure (including trip response delay)	6.0
	CEA insertion begins	6.5
	Peak reactor power occurred	6.5
	Pressurizer safety valves opened	7.0
	Peak primary pressure occurred	7.8
	CEAs fully inserted	9.4
	Steam generator Bank 1 MSSVs opened (both SGs)	9.5
Secondary Side Overpressure (HFP)	Turbine trip	0.0
	Steam generator Bank 1 MSSVs opened (both SGs)	4.4
	Pressurizer PORV opened	4.6
	High Pressurizer Pressure trip setpoint reached	6.0
	Reactor trip occurred on High Pressurizer Pressure (including trip response delay)	6.9
	SG-1 Bank 2 MSSVs opened	7.3
	SG-2 Bank 2 MSSVs opened	7.4
	CEA insertion begins	7.4
	Peak reactor power occurred	7.4
	CEAs fully inserted	10.3
	Peak secondary pressure occurred	13.2
MDNBR	Turbine trip	0.0
	Pressurizer PORV opened	4.6
	Steam generator Bank 1 MSSVs opened (both SGs)	4.8
	High Pressurizer Pressure trip setpoint reached	6.3
	Reactor trip occurred on High Pressurizer Pressure (including trip response delay)	7.2
	CEA insertion begins	7.7
	Peak reactor power occurred	7.7
	MDNBR	8.0

Table 2.8.5.2.1-2
Loss of External Load
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis	Limit
MDNBR	Not explicitly calculated	1.942	1.164
Primary System Pressure	2714 psia	2708 psia	2750 psia
Secondary System Pressure	1074 psia	1090 psia (HFP)	1100 psia

Table 2.8.5.2.1-3
Loss of External Load: Inoperable MSSV Results

Maximum Number of Inoperable MSSVs on Any SG	Peak Secondary Side Pressure (psia)	Maximum Allowed Power Level – High Trip Setpoint (% RTP)
1	1097	93.2
2	1093	79.8
3	1091	66.5

Figure 2.8.5.2.1-1
Loss of External Load
(Primary Side Pressure)
Reactor Power

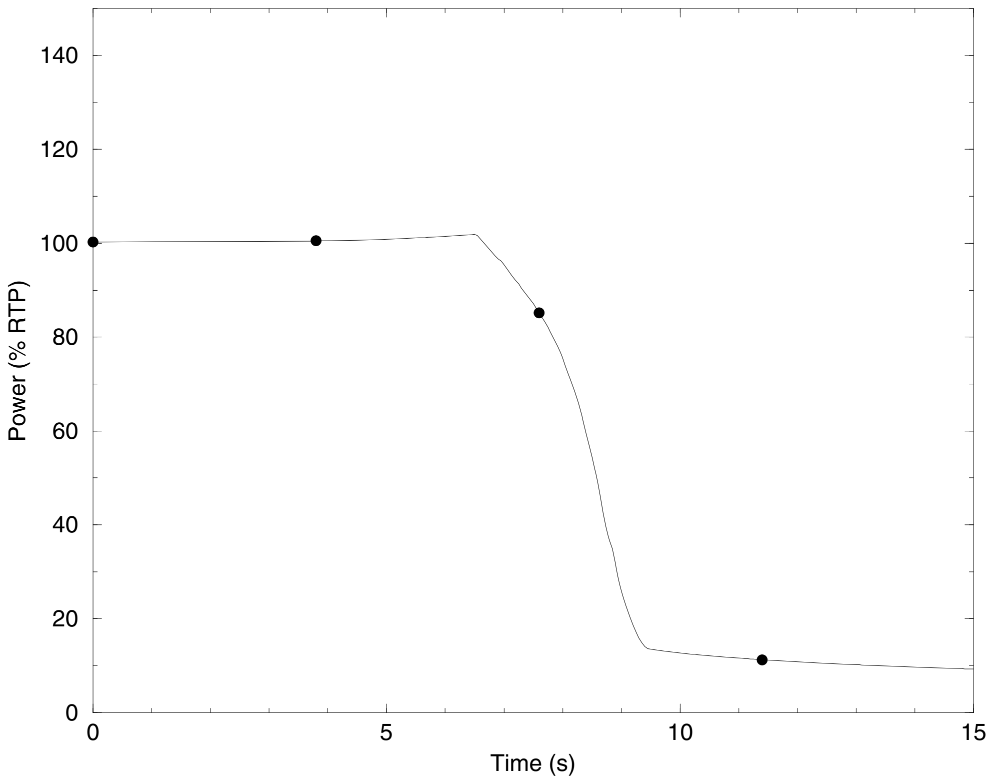


Figure 2.8.5.2.1-2
Loss of External Load
(Primary Side Pressure)
Pressurizer Pressure

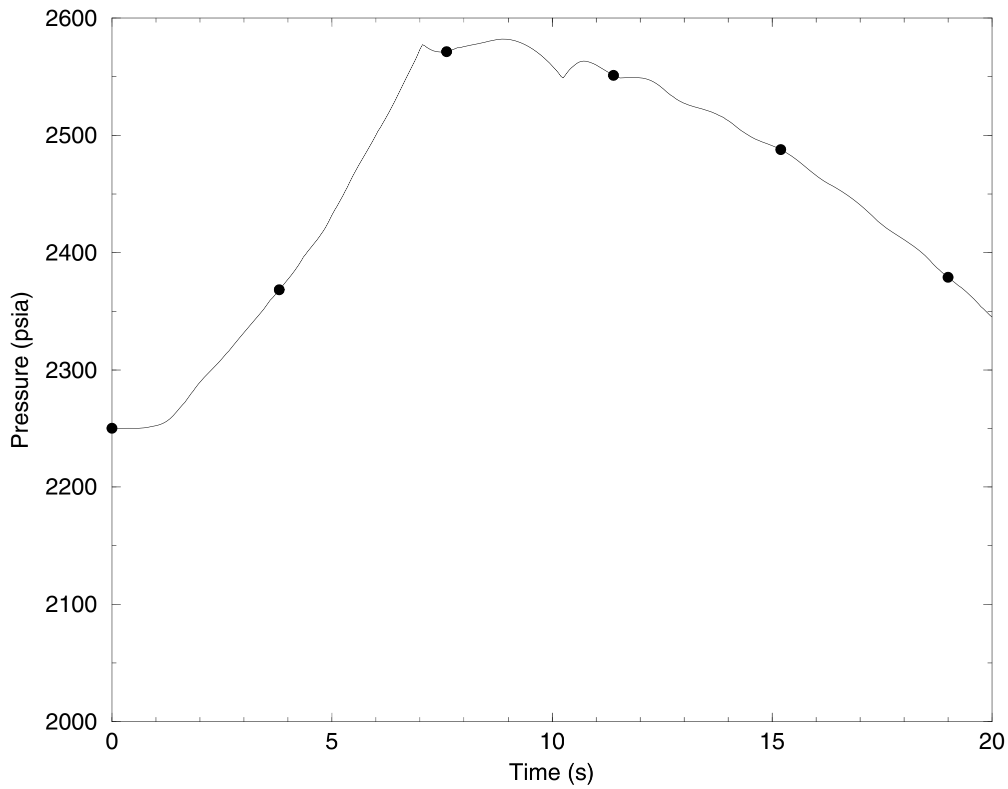


Figure 2.8.5.2.1-3
Loss of External Load
(Primary Side Pressure)
Pressurizer Liquid Level

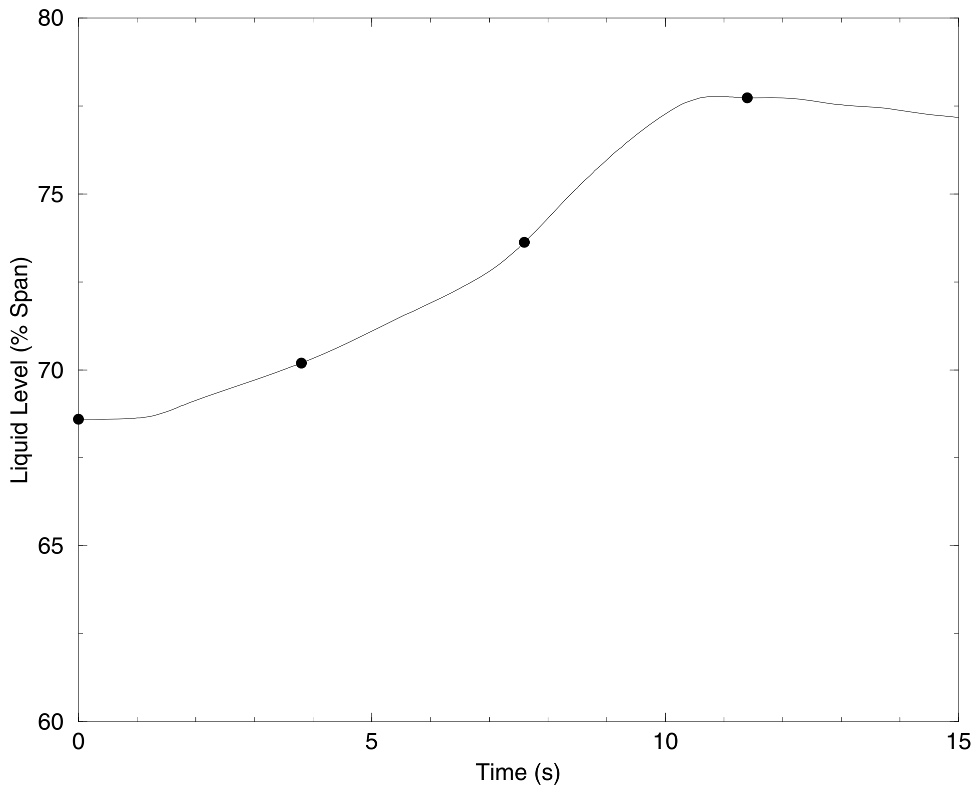


Figure 2.8.5.2.1-4
Loss of External Load
(Primary Side Pressure)
Pressurizer Safety Valve Flow

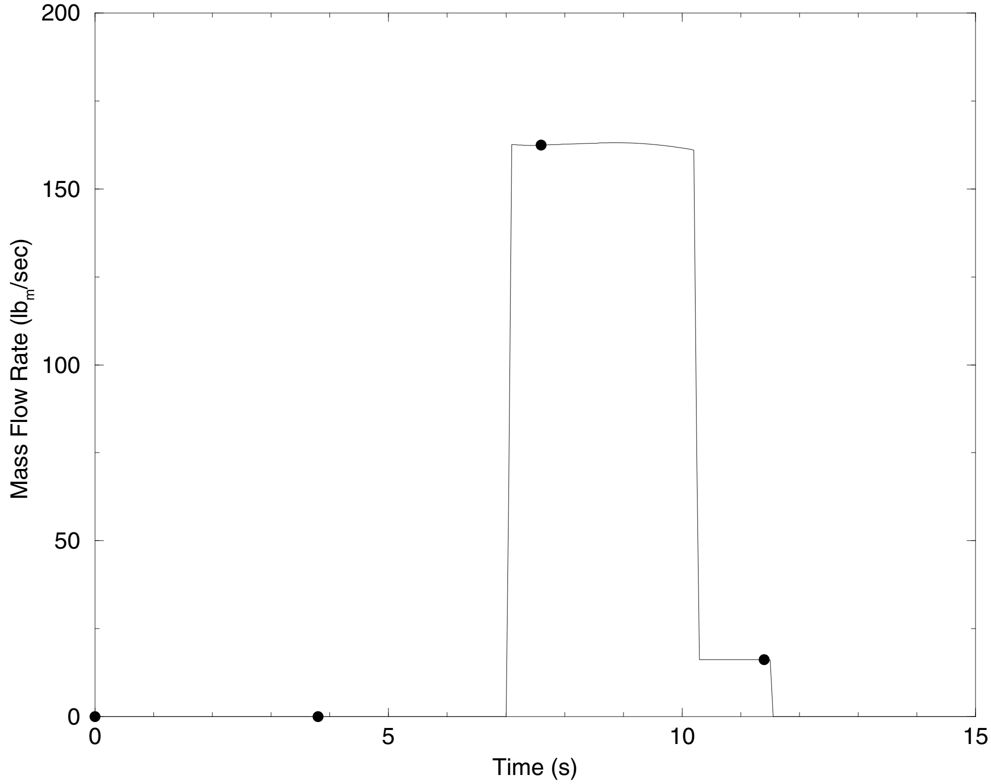


Figure 2.8.5.2.1-5
Loss of External Load
(Primary Side Pressure)
RCS Loop Temperatures

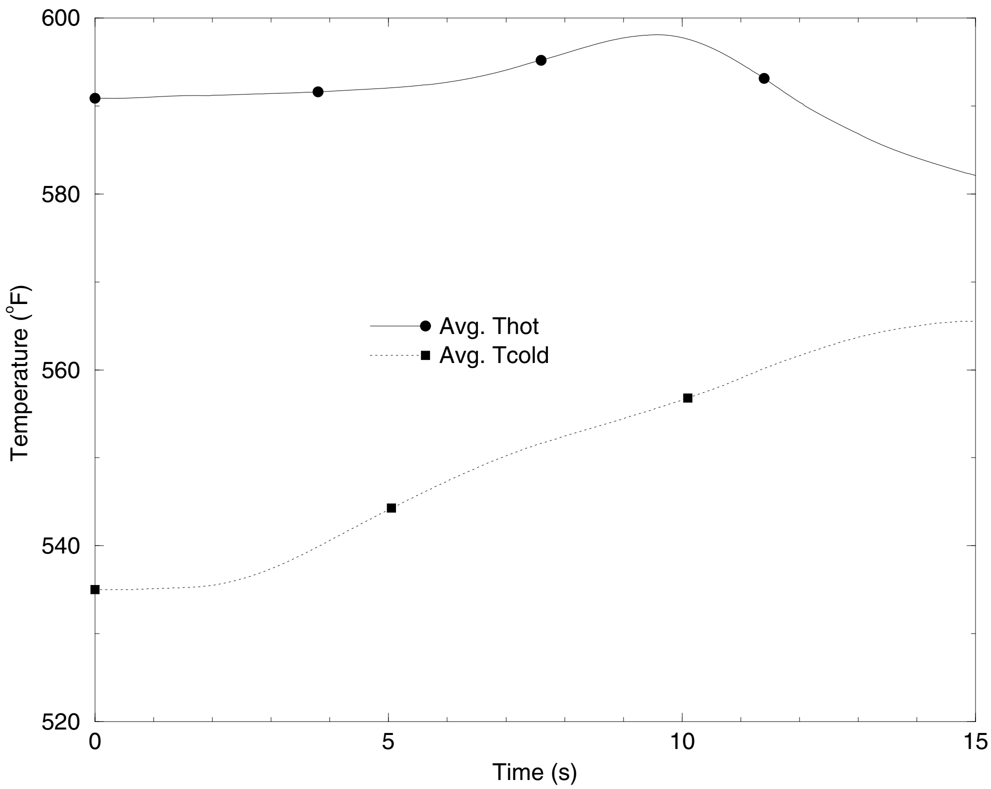


Figure 2.8.5.2.1-6
Loss of External Load
(Primary Side Pressure)
RCS Total Loop Flow Rate

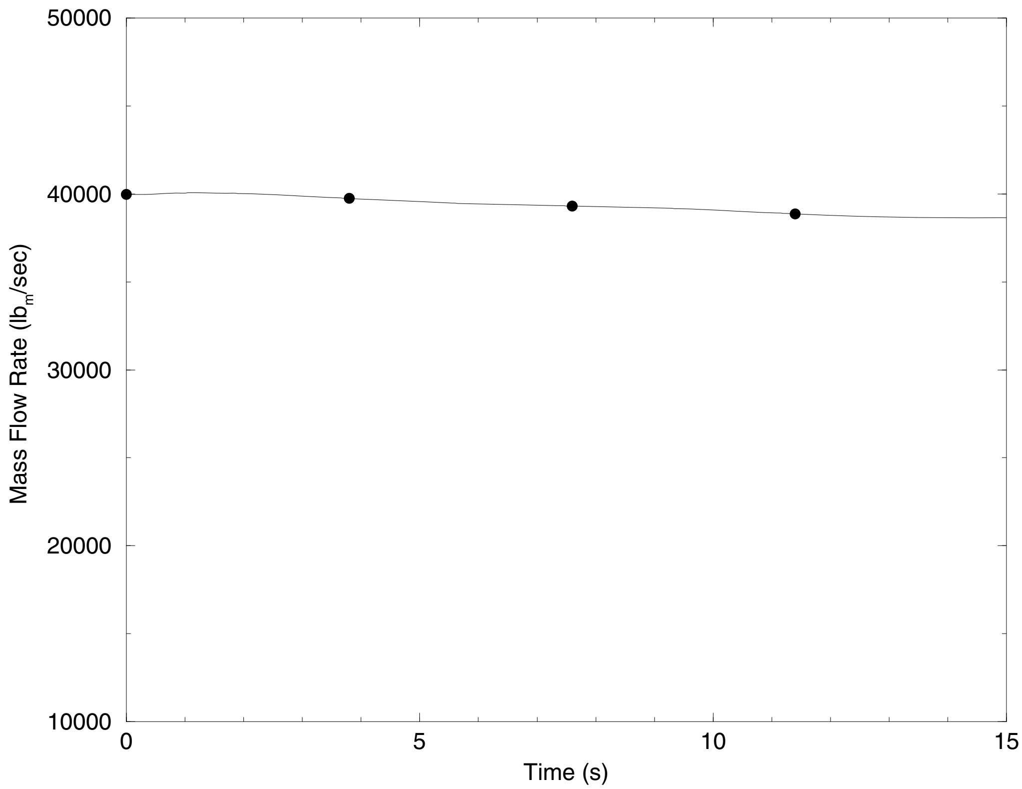


Figure 2.8.5.2.1-7
Loss of External Load
(Primary Side Pressure)
Steam Generator Pressures

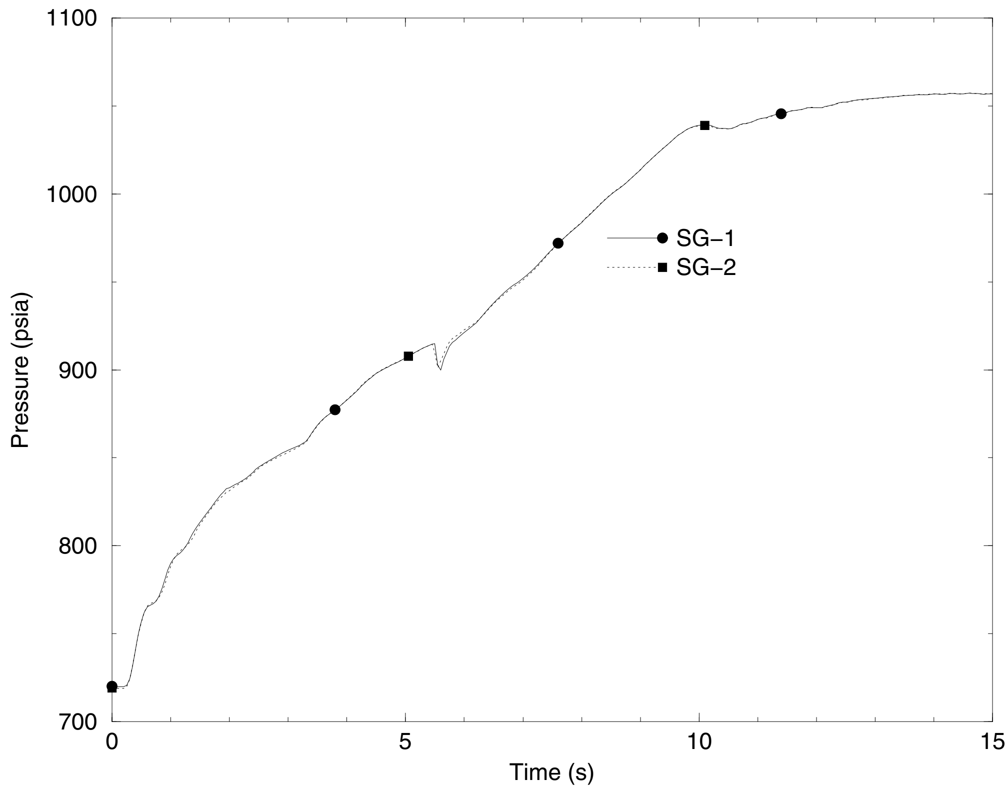


Figure 2.8.5.2.1-8
Loss of External Load
(Primary Side Pressure)
MSSV Flow Rates

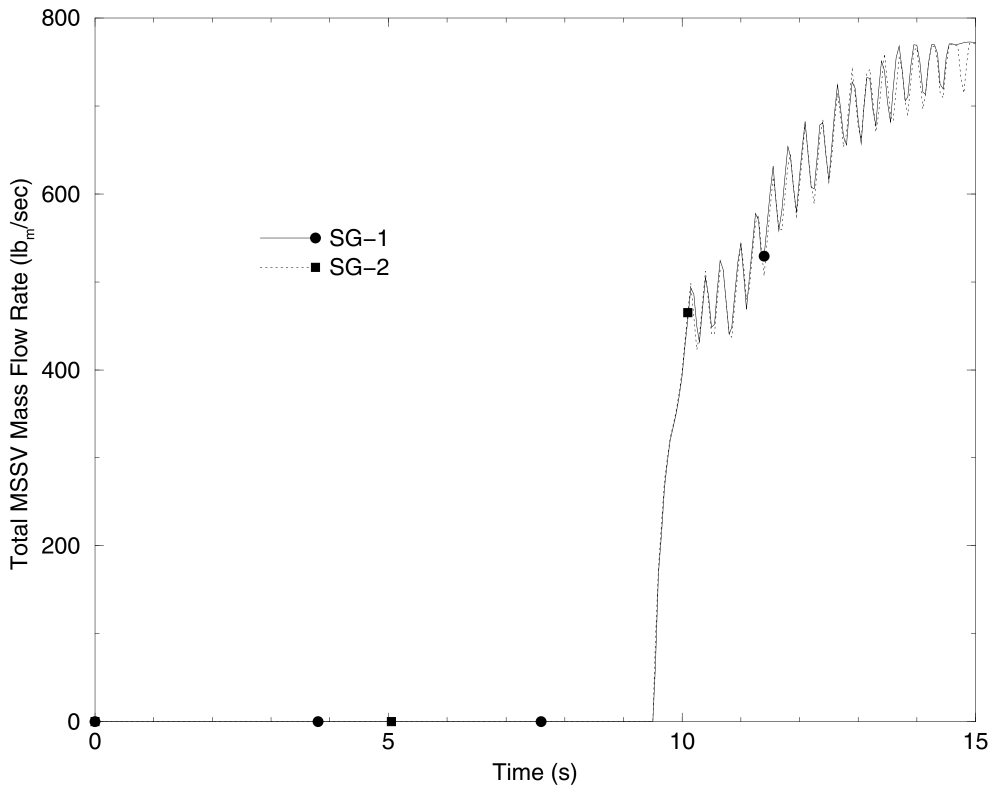


Figure 2.8.5.2.1-9
Loss of External Load
(Primary Side Pressure)
Reactivity Feedback

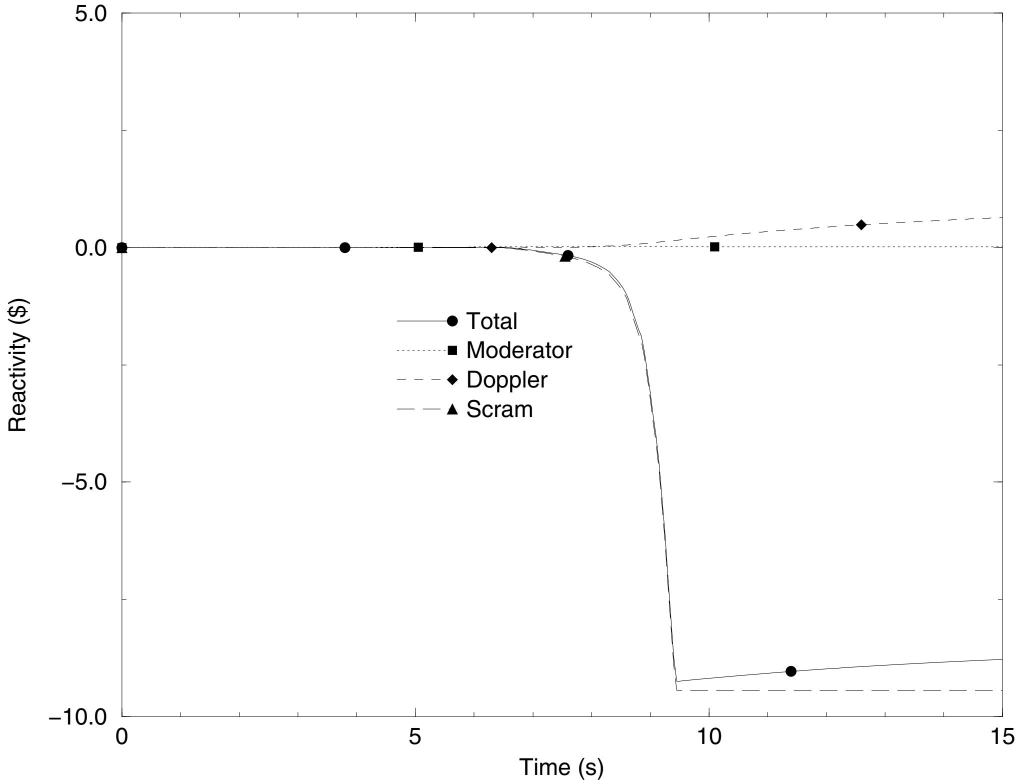


Figure 2.8.5.2.1-10
Loss of External Load
(Primary Side Pressure)
Peak RCS Pressure

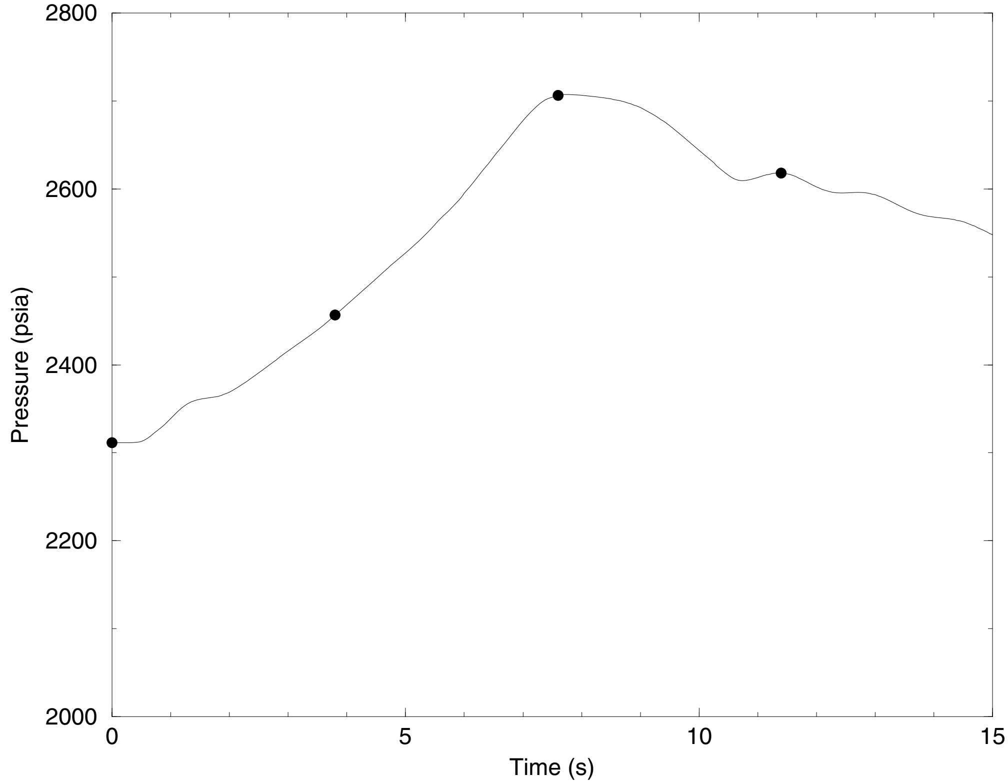


**Figure 2.8.5.2.1-11
Loss of External Load
(Secondary Side Pressure)
Reactor Power**

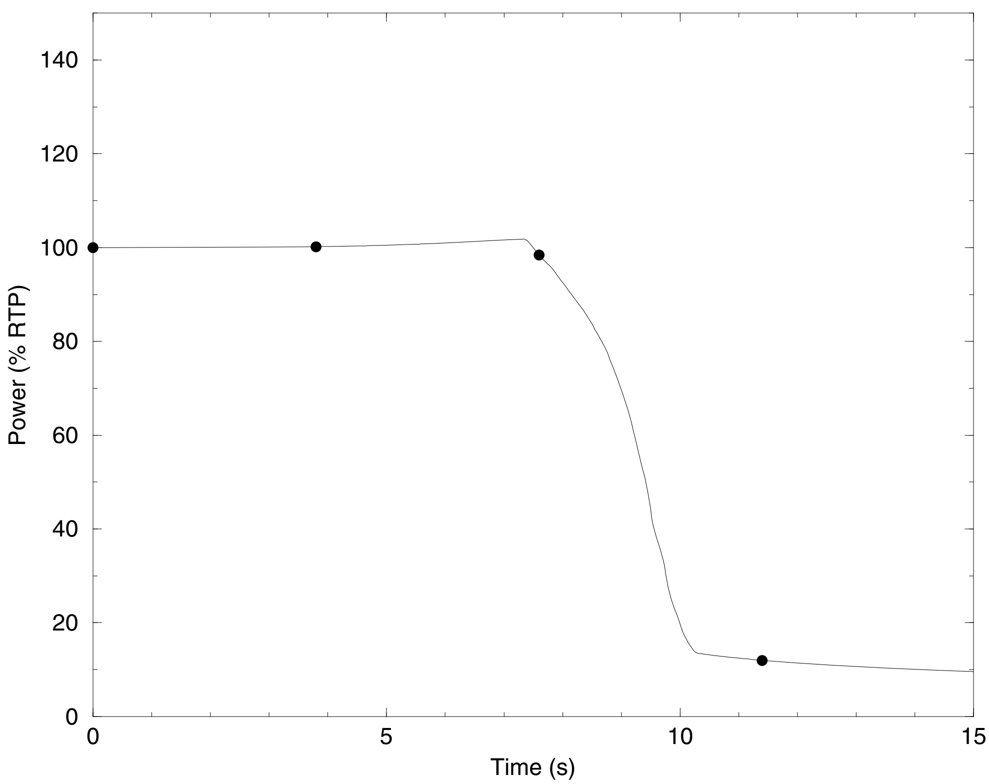


Figure 2.8.5.2.1-12
Loss of External Load
(Secondary Side Pressure)
Pressurizer Pressure

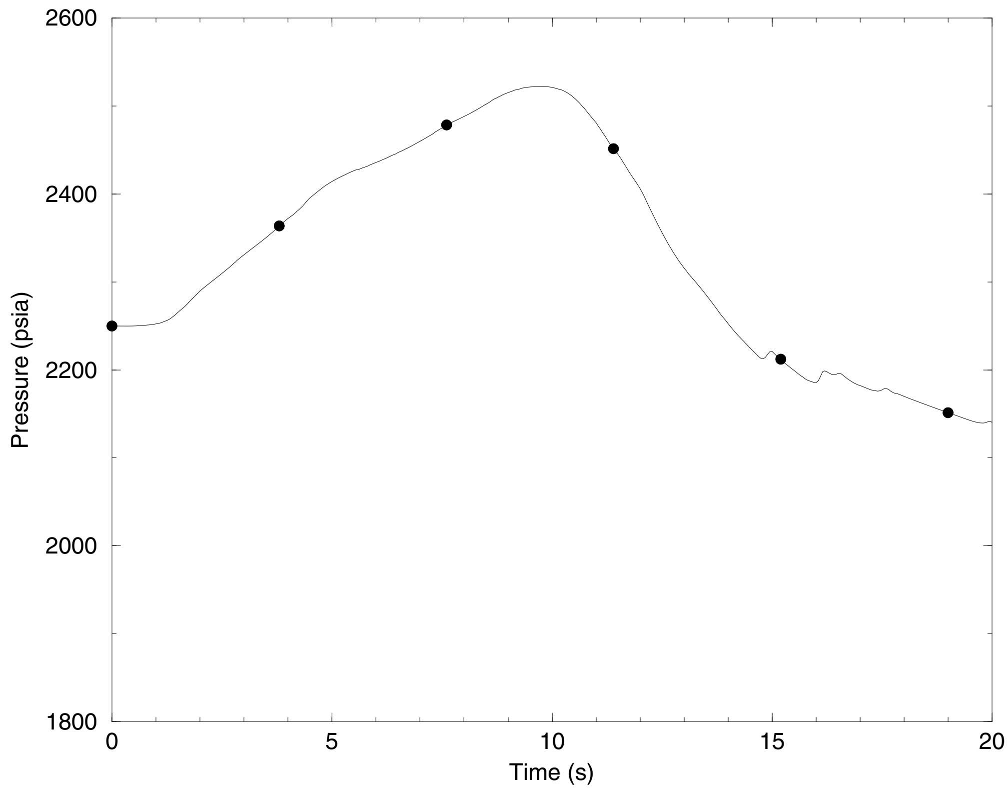


**Figure 2.8.5.2.1-13
Loss of External Load
(Secondary Side Pressure)
Pressurizer Liquid Level**

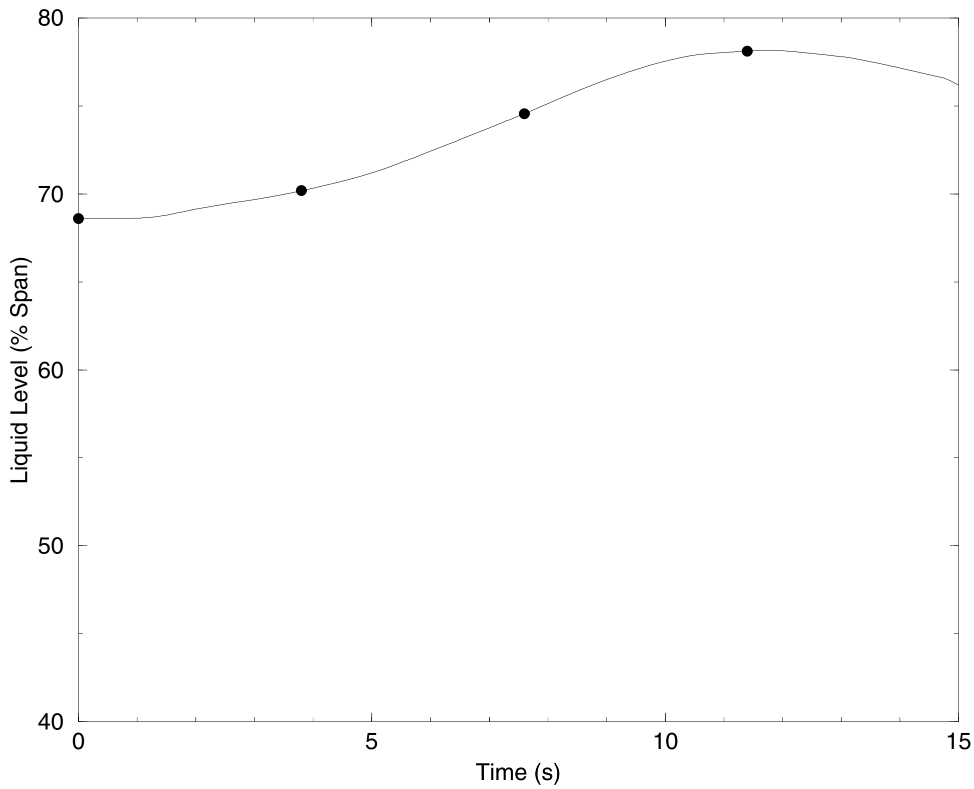


Figure 2.8.5.2.1-14
Loss of External Load
(Secondary Side Pressure)
RCS Loop Temperatures

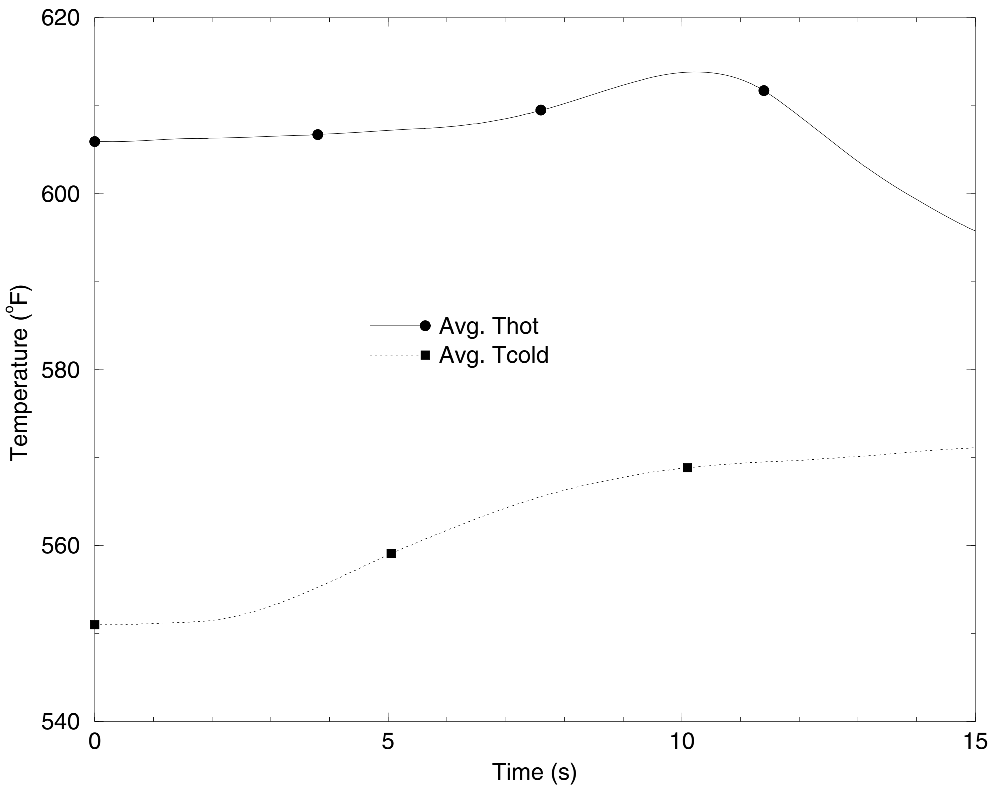


**Figure 2.8.5.2.1-15
Loss of External Load
(Secondary Side Pressure)
RCS Total Loop Flow Rate**

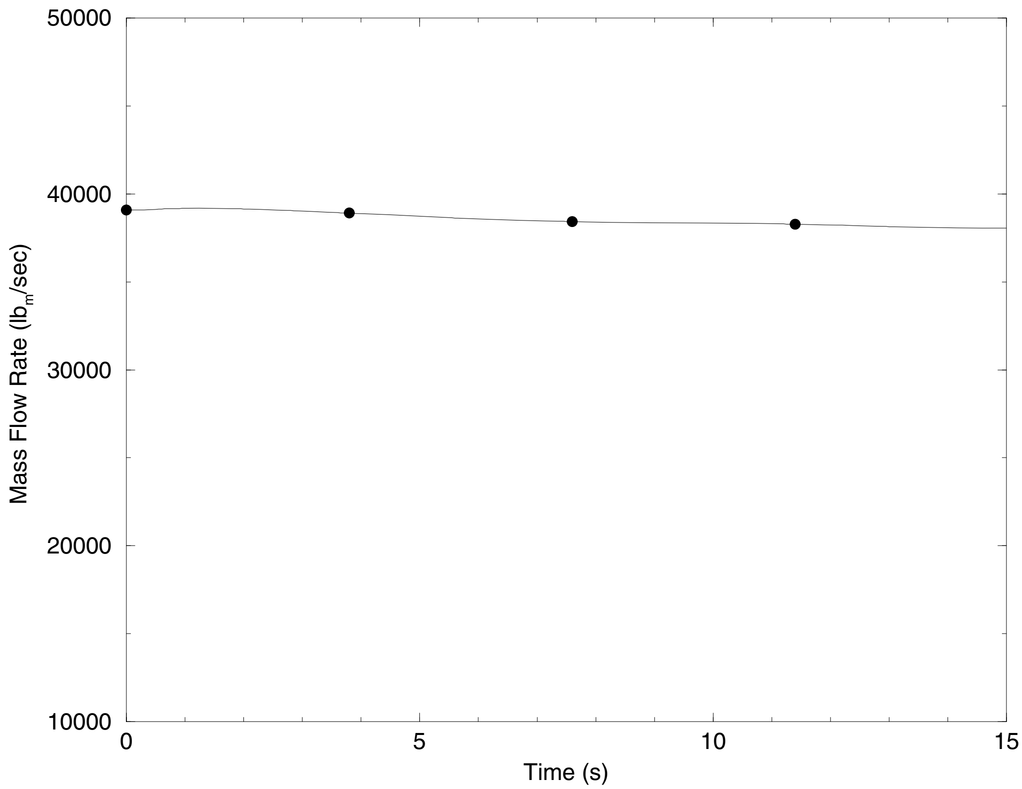


Figure 2.8.5.2.1-16
Loss of External Load
(Secondary Side Pressure)
Steam Generator Pressures

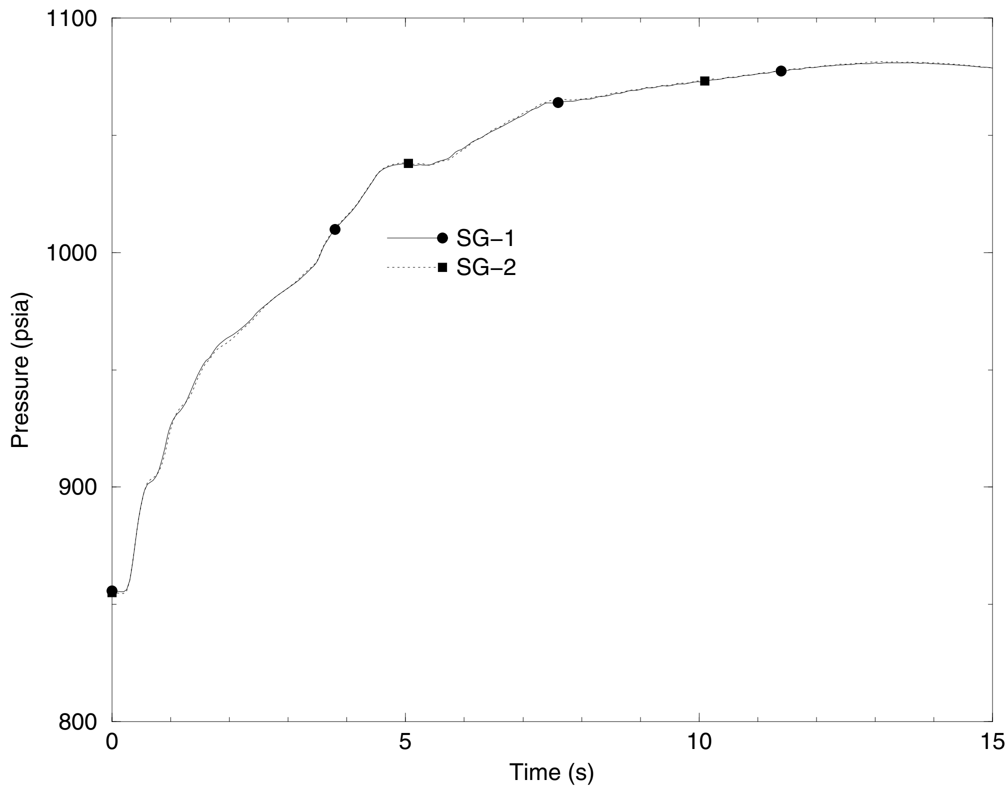


Figure 2.8.5.2.1-17
Loss of External Load
(Secondary Side Pressure)
MSSV Flow Rates

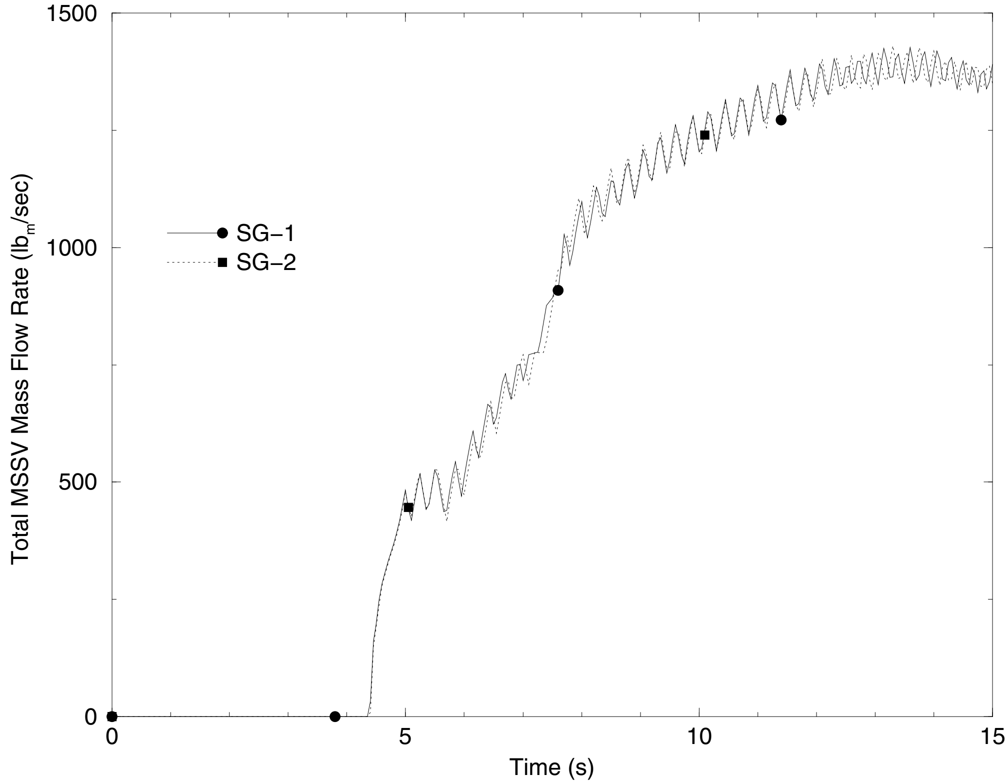


Figure 2.8.5.2.1-18
Loss of External Load
(Secondary Side Pressure)
Reactivity Feedback

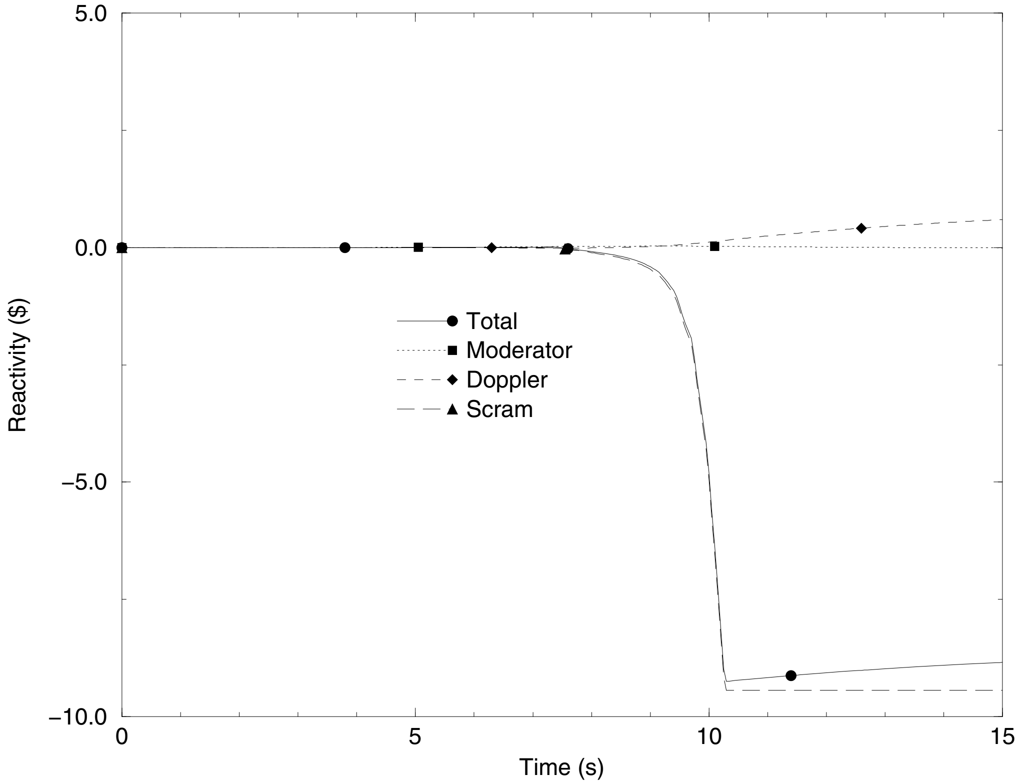


Figure 2.8.5.2.1-19
Loss of External Load
(Secondary Side Pressure)
Peak Secondary Side Pressure

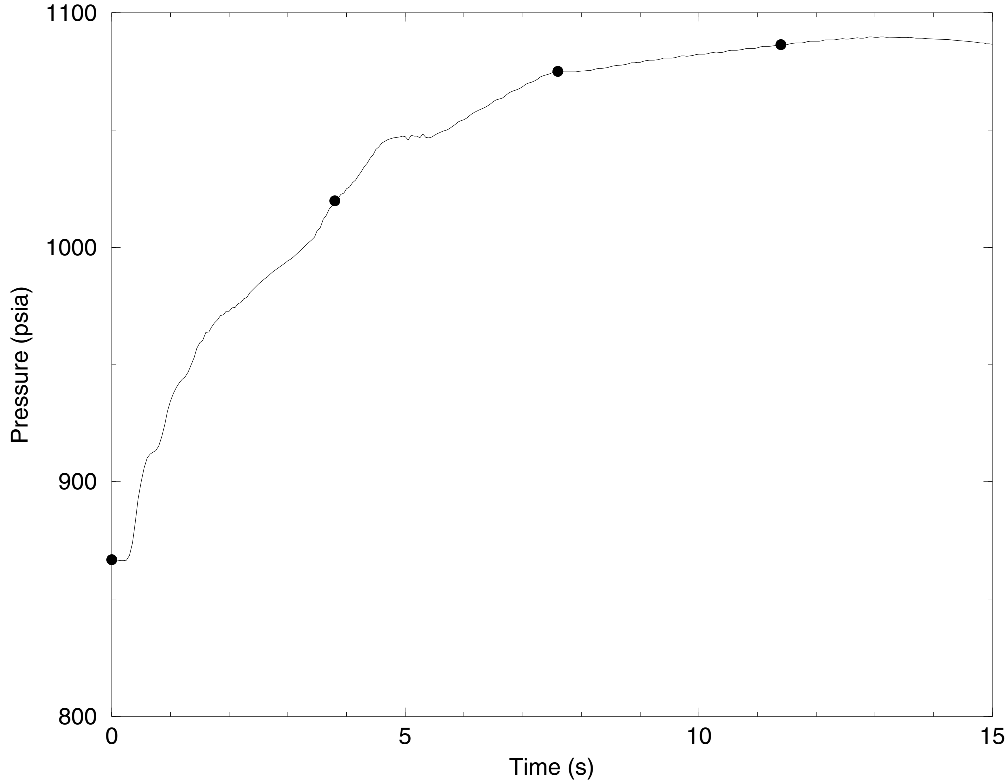


Figure 2.8.5.2.1-20
Loss of External Load
(MDNBR)
Reactor Power

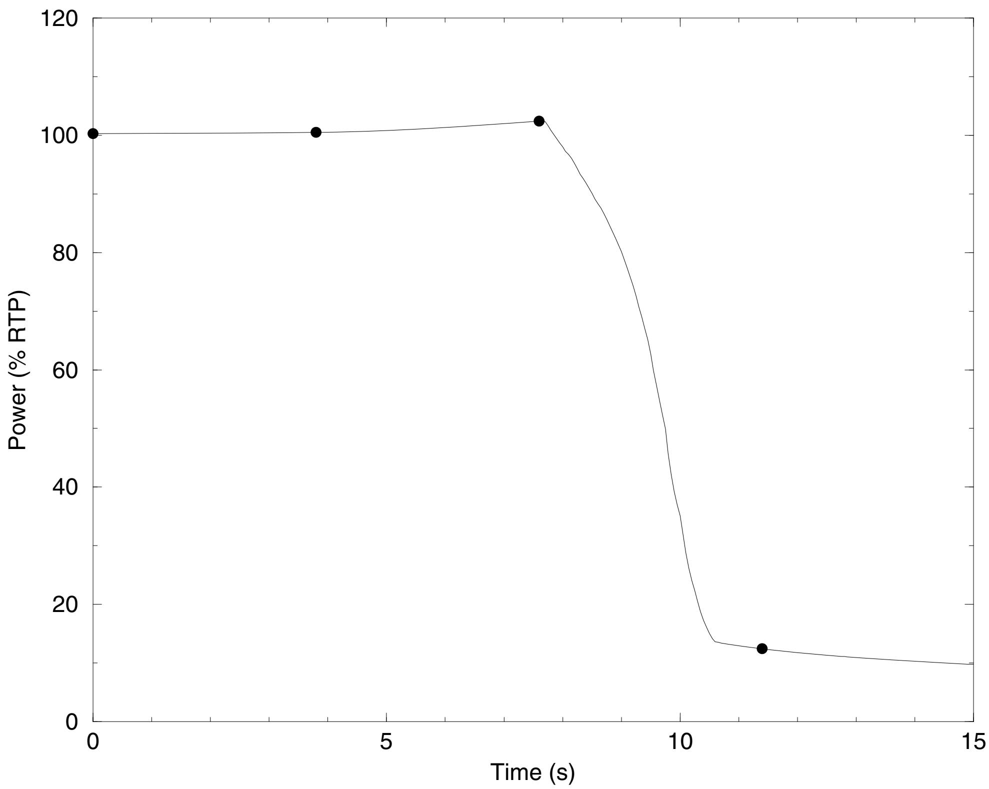


Figure 2.8.5.2.1-21
Loss of External Load
(MDNBR)
Total Core Heat Flux Power

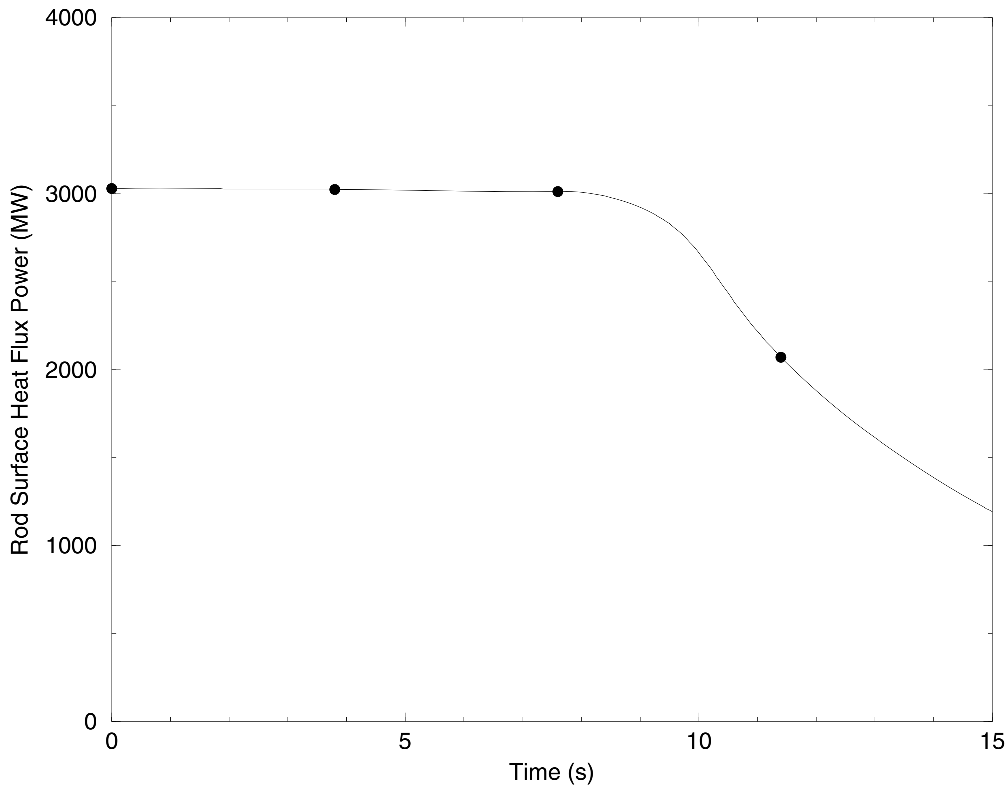


Figure 2.8.5.2.1-22
Loss of External Load
(MDNBR)
Pressurizer Pressure

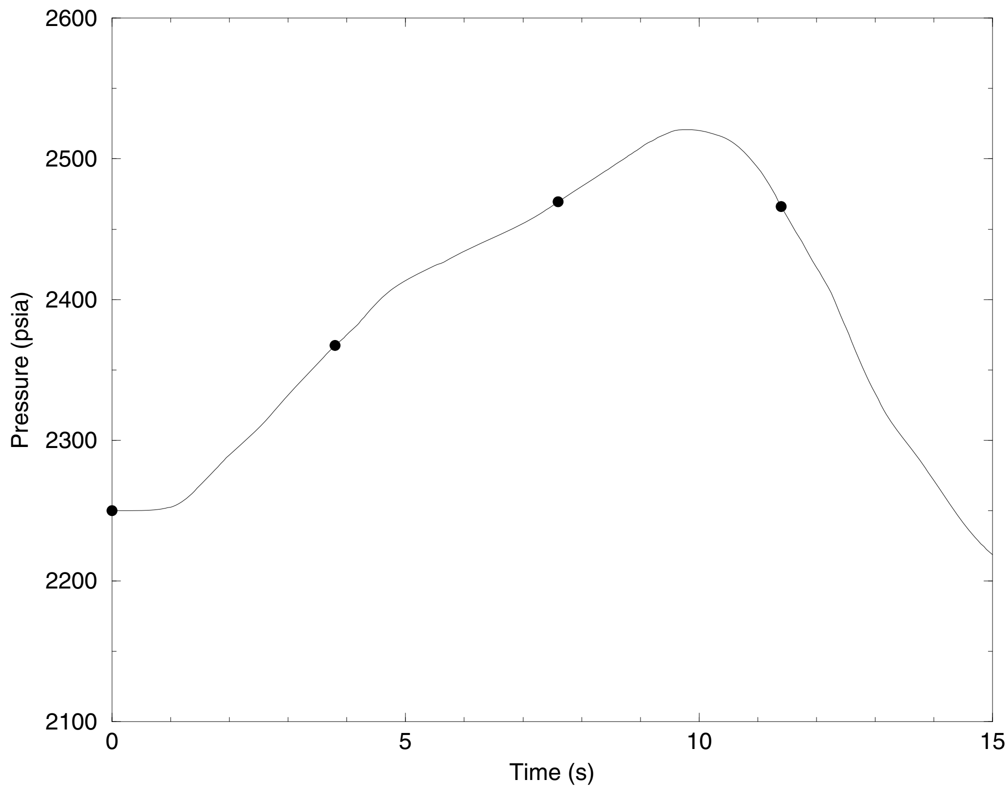


Figure 2.8.5.2.1-23
Loss of External Load
(MDNBR)
Pressurizer Liquid Level

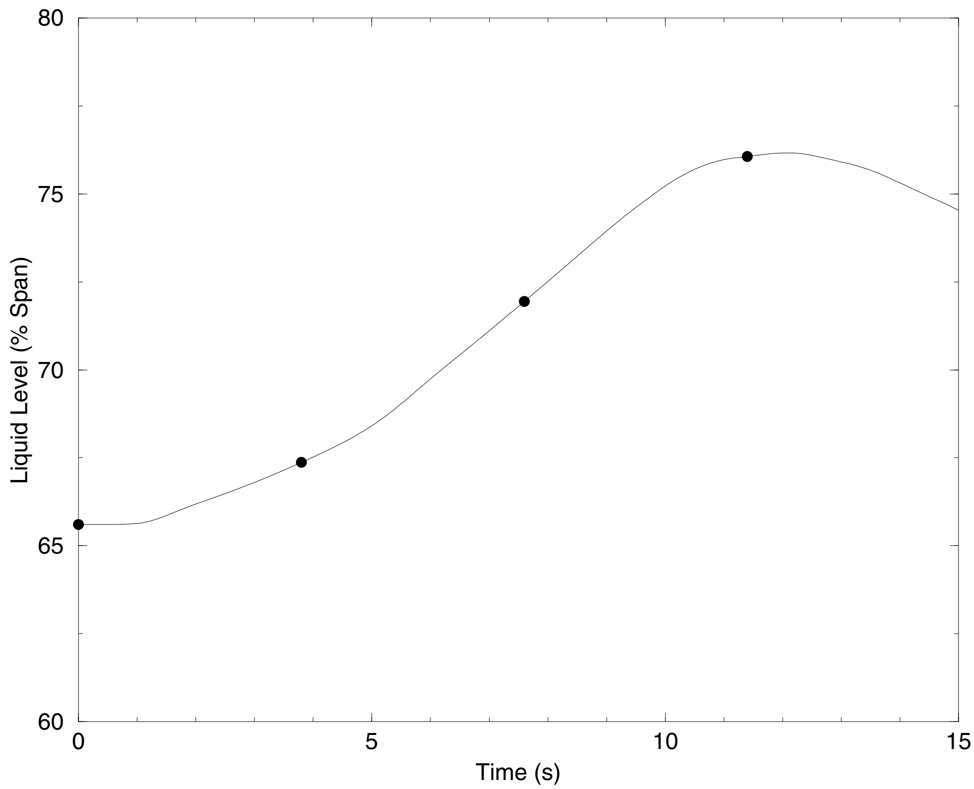


Figure 2.8.5.2.1-24
Loss of External Load
(MDNBR)
Pressurizer PORV Flow Rate

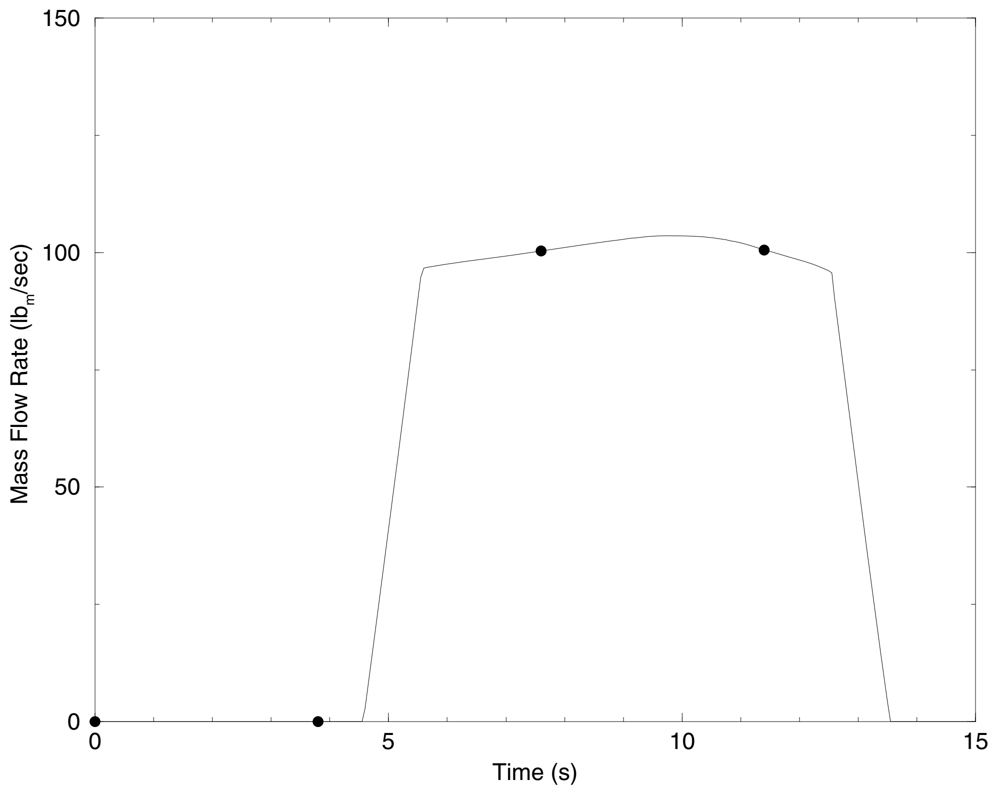


Figure 2.8.5.2.1-25
Loss of External Load
(MDNBR)
RCS Loop Temperatures

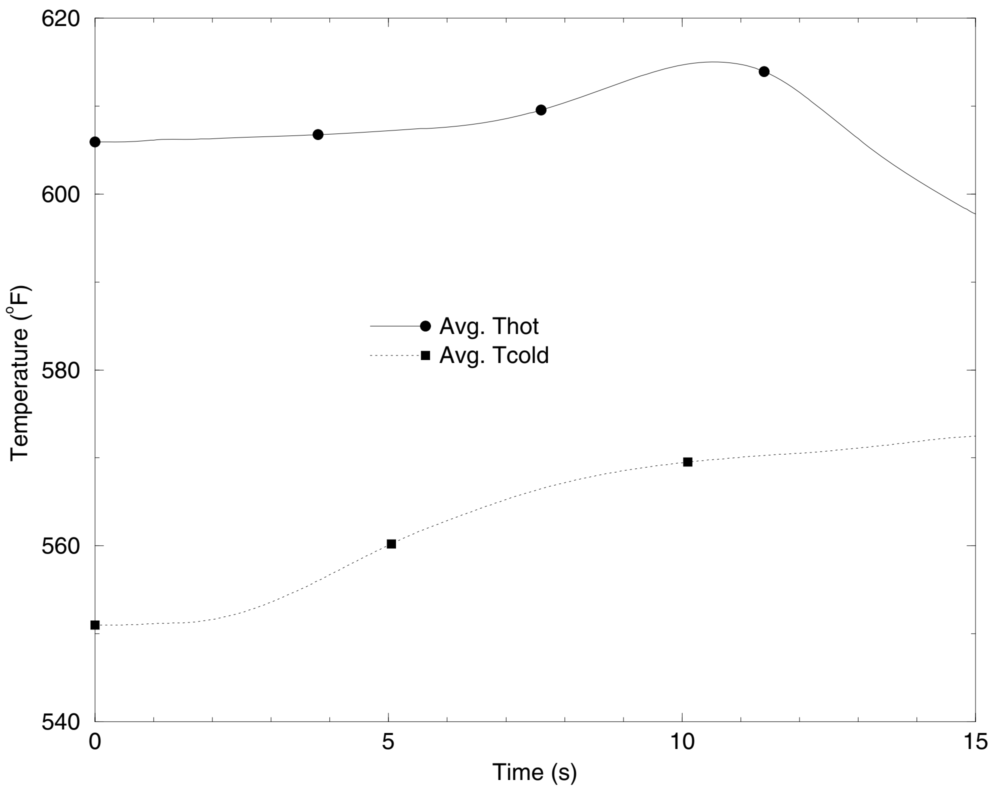


Figure 2.8.5.2.1-26
Loss of External Load
(MDNBR)
RCS Total Loop Flow Rate

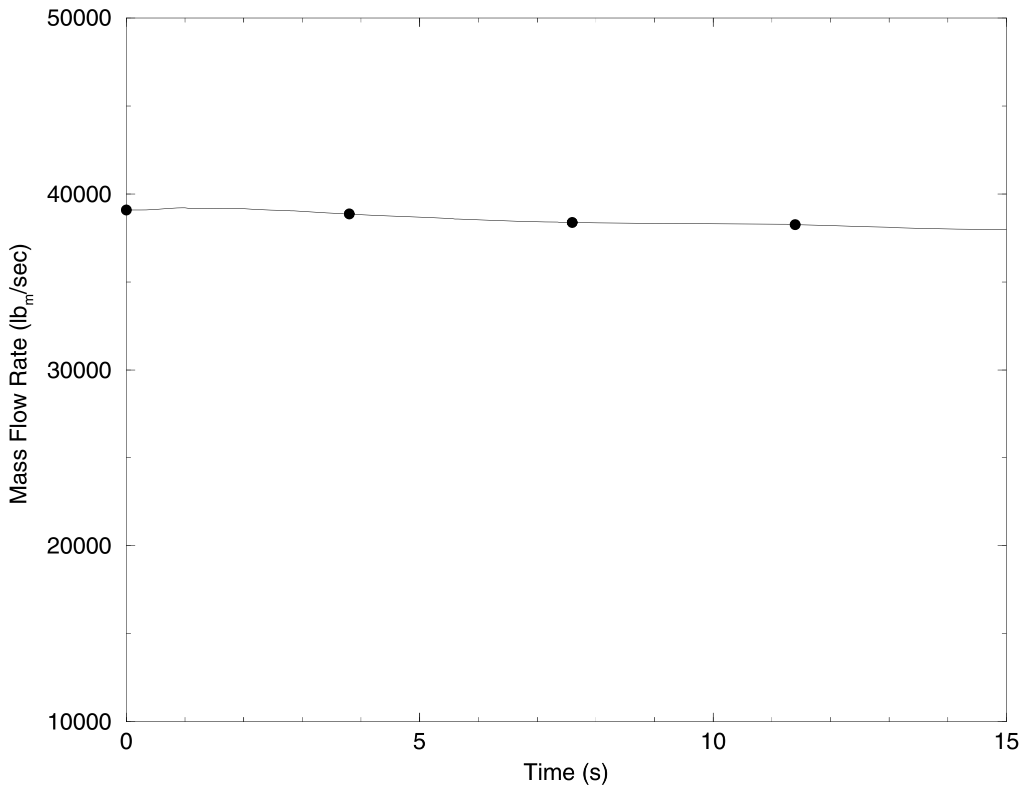


Figure 2.8.5.2.1-27
Loss of External Load
(MDNBR)
Steam Generator Pressures

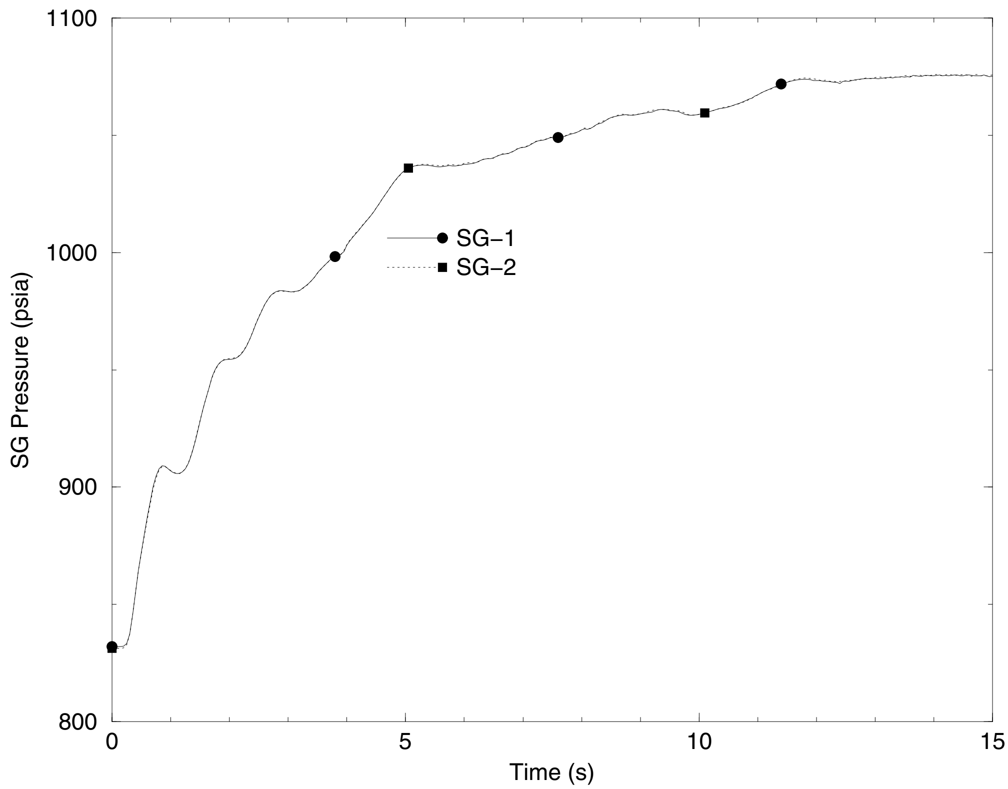
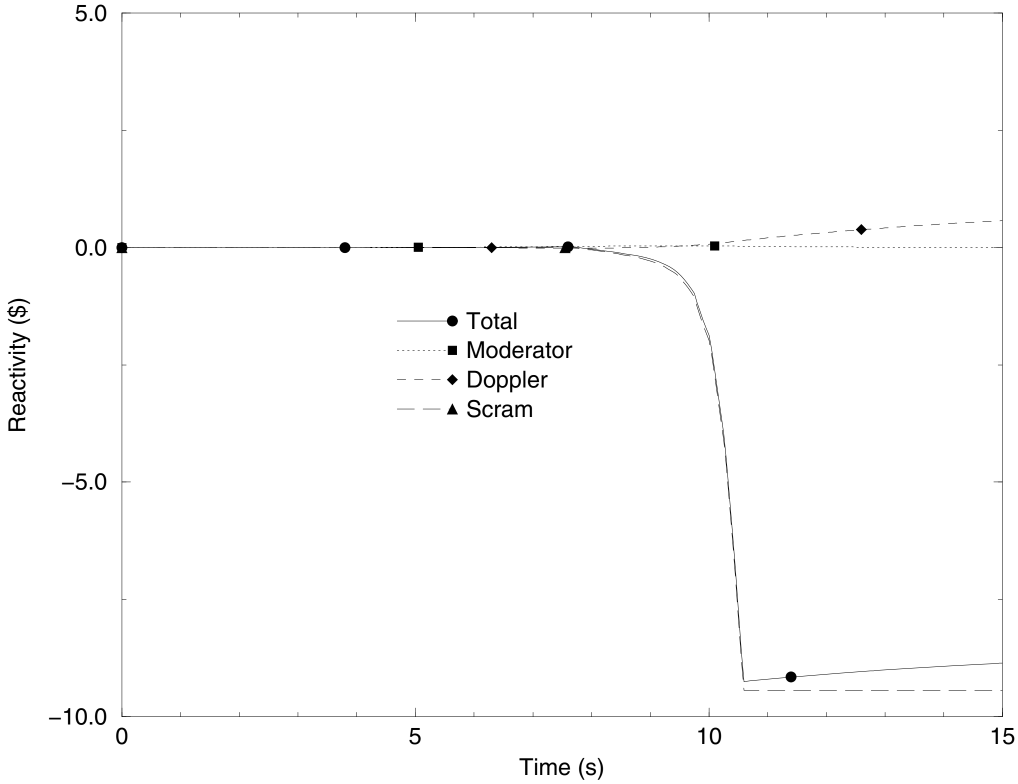


Figure 2.8.5.2.1-28
Loss of External Load
(MDNBR)
Reactivity Feedback



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 is assumed to result in the loss of all power to the station auxiliaries, and the simultaneous tripping of all reactor coolant pumps (RCPs). 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 reactor coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient.

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:

- 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 SRP Section 15.2.6 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the loss of non-emergency AC power to station auxiliaries 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.

The ANSI N18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of 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 control element assemblies (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 AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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 acceptable fuel design limits are not exceeded. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the loss of non-emergency AC power to the station auxiliaries event is provided in UFSAR Section 15.2.9.

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.

2.8.5.2.2.2 Technical Evaluation

The loss of AC power event is defined as a complete loss of offsite electrical power and a concurrent turbine trip. Under such circumstances, the plant would experience a simultaneous loss of load, a loss of main feedwater flow, and a loss of forced reactor coolant flow.

The early part of the event (0–10 seconds) is similar to the loss of forced reactor coolant flow event (four-RCP coastdown) (LR Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow) because the steam generator inventory would not have been reduced sufficiently to affect heat removal, and there is no pressure increase due to loss of load. Therefore, the departure from nucleate boiling (DNB) SAFDL is essentially the same as that for the loss of forced reactor coolant flow event.

The challenge to peak primary and secondary overpressure for the loss of AC power event (with secondary-system isolation near the time of reactor scram) is bounded by the loss of external load event, with secondary-system isolation at event initiation and continued reactor power operation for a considerable period of time (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum). Due to natural circulation and the associated higher long-term average RCS temperature for the loss of AC power event relative to the loss of feedwater flow event (LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow), the loss of AC power event will result in a slightly higher pressurizer level than for the loss of feedwater flow event. However, the loss of feedwater flow event does not significantly challenge pressurizer overfill; thus, the loss of AC power event will not challenge pressurizer overfill.

The loss of AC power event is bounded by the loss of normal feedwater flow event (LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow) regarding minimum steam generator inventory because the loss of feedwater flow event has continued RCP operation with its associated pump heat input to the RCS. In addition, with the RCPs running, the average long-term RCS temperature will be lower than for the loss of AC power event with natural circulation, thus more energy must be removed from the RCS for the loss of feedwater flow event.

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 the EPU conditions (loss of forced reactor coolant flow, loss of external load, and loss of normal feedwater). 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 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.

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:

- GDC-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limit (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;
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of 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 control element assemblies (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 AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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 acceptable fuel design limits are not exceeded. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the loss of normal feedwater flow event is provided in UFSAR Section 15.2.8.

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.

2.8.5.2.3.2 Technical Evaluation

2.8.5.2.3.2.1 Introduction

This event is initiated by a malfunction of the main feedwater (MFW) system, resulting in the total loss of normal feedwater flow to both steam generators (SGs). A sudden loss of subcooled MFW flow causes SG heat removal rates to decrease and SG levels to drop as the plant continues to operate at power. This, in turn, causes reactor coolant temperatures to increase. The reactor coolant expands, surging into the pressurizer.

SG liquid levels, which have been steadily dropping since the termination of MFW flow, soon reach the low SG level reactor trip setpoint. This initiates a reactor scram, thereby ending the short-term-heatup phase of the event.

The automatic turbine trip at reactor scram, in conjunction with the continuing primary-to-secondary transfer of the core decay heat and the reactor coolant pump (RCP) heat, cause SG pressures to increase.

SG levels continue to drop and soon reach the low-low SG level auxiliary feedwater (AFW) actuation setpoint. This initiates the starting sequence for the AFW pumps.

As the delivery of AFW begins and the decay heat level drops, liquid levels in the fed SG stabilize and then begin to rise, which causes reactor coolant temperatures to stabilize and then to begin to decrease.

The single active failure assumed for this event is the loss of the turbine-driven AFW pump. The turbine-driven AFW pump is higher capacity than a motor-driven AFW pump, so its loss produces more severe consequences.

2.8.5.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – This event was analyzed from hot full power (HFP) which produces the highest decay heat level and the most significant challenge to the AFW system to remove decay heat.
- Reactivity Feedback – Since this event involves an increase in the core coolant temperature, the event is assumed to occur at beginning of cycle (BOC) with a maximum TS/core operating limits report (COLR) moderator temperature coefficient (MTC) at full power. However, this event is generally not sensitive to neutronic parameters.
- Decay Heat – Decay heat was calculated using the 1973 ANS standard plus actinides in accordance with the approved methodology.
- Reactor Protection System (RPS) Trips and Delays – This event is primarily protected by the low SG level trip. The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion is delayed to account for the CEA holding coil delay time.
- Steam Generator Blowdown – SG blowdown is assumed to be in operation during this event.
- Offsite Power – To maximize RCP heat, it was assumed that offsite power was available and that the RCPs continued to run with a conservative heat input of 20 MWt.
- Auxiliary Feedwater – Two motor-driven AFW pumps were assumed to deliver AFW flow to each SG. A single failure of the higher capacity turbine-driven AFW pump was assumed. These assumptions minimized the SG inventory during the event, thereby maximizing the challenge to the acceptance criteria.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The acceptance criteria for this event are:

- The pressures in the RCS and main steam system should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.
- The event should not generate a more serious plant condition without other faults occurring independently (some plants may challenge pressurizer overfill which could result in loss of pressure control).

The pressure acceptance criterion requires that the pressures in the RCS and steam systems must be maintained below 110% of their respective system design pressures. The challenges to peak primary and secondary overpressure are less for this event (with secondary-system isolation coincident with the reactor trip) than for the loss of external load event (with early termination of secondary-system steam flow and continued operation at power until reactor trip). Thus, the primary system pressure limit is satisfied for this event, as long as the pressurizer does not become liquid-filled and the pressurizer retains a steam “bubble” for pressure control. In addition, the peak secondary system pressure is bounded by the peak secondary system pressure in the loss of external load event. Thus, the secondary system overpressure limit is satisfied for this event since the limit was demonstrated to be satisfied in the loss of external load event (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum).

The departure from nucleate boiling (DNB) SAFDL is not challenged during the short-term heatup phase of the event because the reactor coolant conditions at reactor scram are close to the initial steady-state values. The DNB SAFDL is not challenged during the long-term decay heat removal phase of the event provided that RCS subcooling is sufficient for decay heat removal. Thus, the DNB SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

The fuel centerline melt (FCM) SAFDL is not challenged during the short-term-heatup phases of this event because the reactor power level and peaking at scram are close to the initial steady-state values. The FCM SAFDL is not challenged during the long-term decay heat removal phase of the loss of normal feedwater flow events provided that RCS subcooling is sufficient for decay heat removal. Thus, the FCM SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

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, adequate steam volume must be maintained in the pressurizer to maintain pressure control. This plant condition criterion is satisfied for this event if the pressurizer does not overfill.

2.8.5.2.3.2.3 Description of Analyses and Evaluations

Under extended power uprate (EPU) conditions, higher power level produces higher heat load on SGs, promoting faster depletion of SG inventory, and higher decay heat increases the challenge to long term decay heat removal. This increases the challenge to the capability of the main steam safety valves (MSSVs) and AFW to remove decay heat. The increase in RCS temperature does not significantly affect the consequences of the event.

The current licensing basis calculations were performed with the non-LOCA methodology, using the ANF-RELAP code (Reference 1). For the EPU, detailed analyses were performed with the approved methodology using the S-RELAP5 code (Reference 2) to address the UFSAR Chapter 15 event.

A single limiting case with offsite power available and RCPs running was analyzed to evaluate minimum SG inventory, long-term decay heat removal, RCS subcooling margin, and pressurizer overfill.

2.8.5.2.3.2.4 Evaluation of 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 transient sequence of events is shown in LR Table 2.8.5.2.3-1. Results of the analysis are given in LR Table 2.8.5.2.3-2.

Transient results are shown in LR Figures 2.8.5.2.3-1 through 2.8.5.2.3-9. LR Figure 2.8.5.2.3-1 shows reactor power as a function of time. LR Figure 2.8.5.2.3-2 shows pressurizer pressure. LR Figure 2.8.5.2.3-3 shows pressurizer liquid level. LR Figure 2.8.5.2.3-4 shows RCS loop temperatures. LR Figure 2.8.5.2.3-5 show total RCS flow rate. LR Figure 2.8.5.2.3-6 shows SG pressures. LR Figure 2.8.5.2.3-7 shows AFW flow rates. LR Figure 2.8.5.2.3-8 shows SG blowdown flow rates. LR Figure 2.8.5.2.3-9 shows the SG total and liquid masses.

There is no significant change in RCS temperature, pressure or power prior to reactor scram, so this event does not challenge the departure from nucleate boiling ratio (DNBR) or FCM SAFDLs. Pressurizer level does not significantly challenge pressurizer overfill. The combination of initial SG mass inventory and AFW flow were able to maintain adequate liquid mass inventories in both SGs, and thereby to remove decay heat until AFW flow exceeded the steam mass lost through the MSSVs and SG inventory recovery began. Thus, there was adequate secondary cooling of the RCS, such that significant RCS subcooling margin was retained. Thus, all acceptance criteria are satisfied for this event.

A direct comparison of the results to the current analysis cannot be made as this event in the UFSAR is covered under the more limiting UFSAR Chapter 10 analysis (see LR Section 2.5.4.5, Auxiliary Feedwater). Compared to the pre-EPU analysis of this event as documented in the UFSAR, the EPU analysis included additional conservatisms with respect to the reactor coolant pump heat and the SG blowdown flow. Additionally, to maximize the RCS heatup, the steam dump and bypass system is not credited so that the secondary pressure is controlled by the main steam safety valves set pressure as compared to the lower pressure corresponding to the steam dump and bypass control system.

2.8.5.2.3.3 Conclusions

FPL has reviewed the analyses of 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. 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 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. Therefore, FPL finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

2.8.5.2.3.4 References

1. ANF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

Table 2.8.5.2.3-1
Loss of Normal Feedwater Flow
Sequence of Events

Event	Time (sec.)
Total loss of main feedwater	0.0
Minimum hot leg subcooling	~6.1
Reactor trip signal generated on low SG level	14.3
Low steam generator level AFW setpoint reached in SG-2	14.6
Low steam generator level AFW setpoint reached in SG-1	14.7
Reactor trip on low SG level (including response delay), and turbine trip on reactor trip	15.2
CEA insertion begins	15.7
Maximum hot leg temperature	17.6
CEAs fully inserted	18.6
First opening of Bank 1 MSSVs in both loops	18.8
Maximum pressurizer pressure	18.9
Maximum RCS average temperature	19.2
Maximum pressurizer level	19.4
First opening of Bank 2 MSSVs in both loops	22.5
Closure of Bank 2 MSSVs in both loops	28.0
Motor-driven AFW pumps begin delivery to feedwater lines, which begins sweepout of hot MFW into the SGs	345
Feedwater piping purged of hot MFW	655
Minimum SG-1 liquid inventory	1373
Minimum SG-2 liquid inventory	1442

Table 2.8.5.2.3-2
Loss of Normal Feedwater Flow
Results

Criterion	EPU Analysis	Limit
Max. pressurizer liquid volume	Less than volume of pressurizer	Less than volume of pressurizer
Min. RCS subcooling, °F	47.1	0

Figure 2.8.5.2.3-1
Loss of Normal Feedwater Flow
Reactor Power

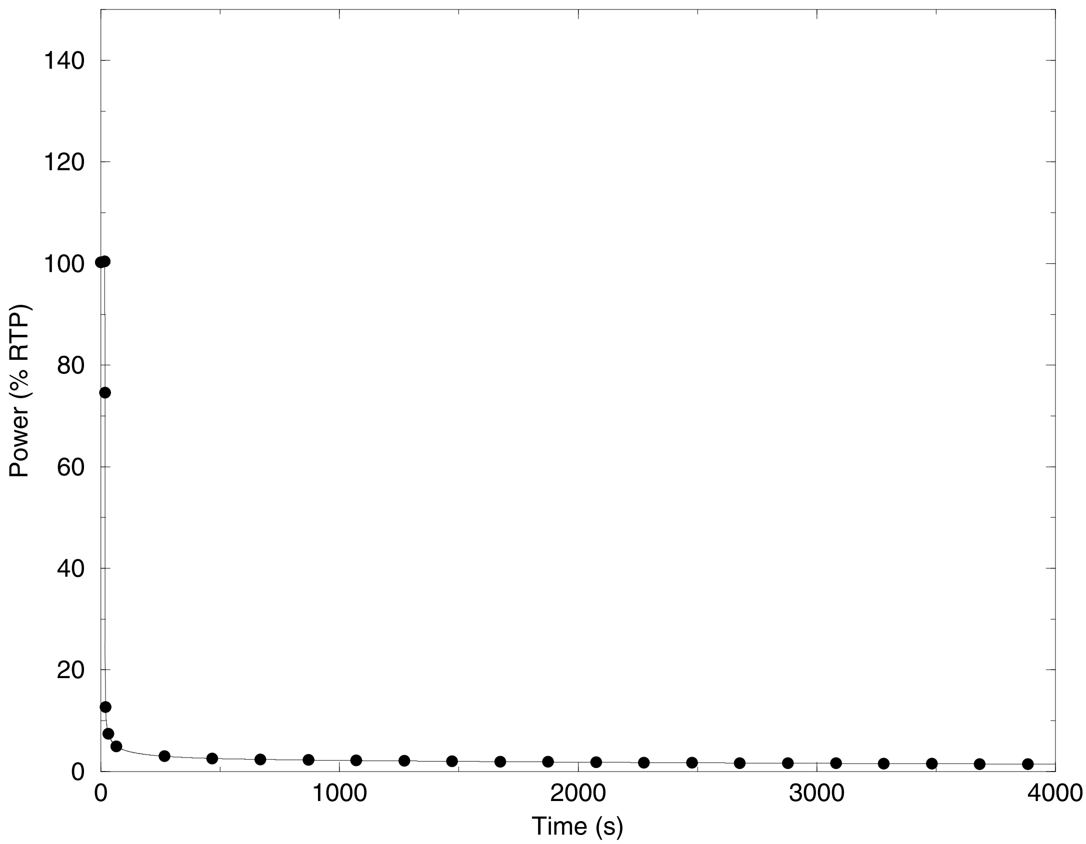


Figure 2.8.5.2.3-2
Loss of Normal Feedwater Flow
Pressurizer Pressure

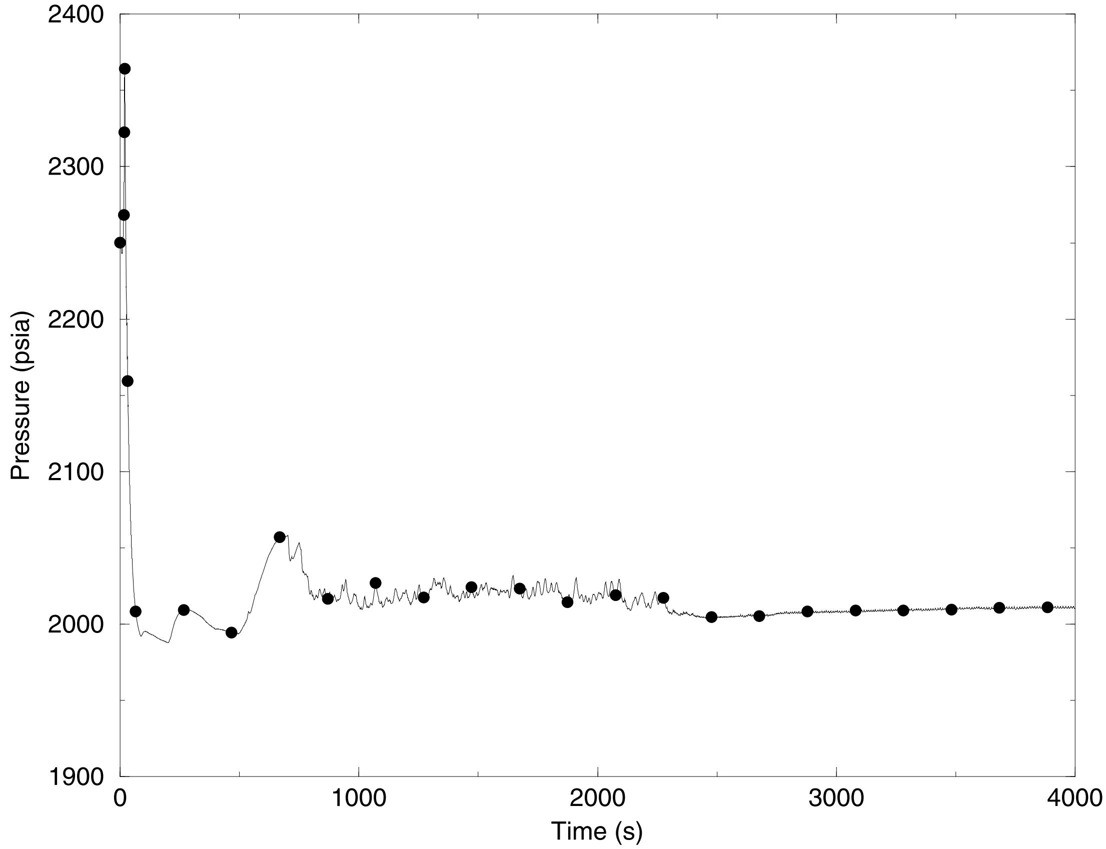


Figure 2.8.5.2.3-3
Loss of Normal Feedwater Flow
Pressurizer Liquid Level

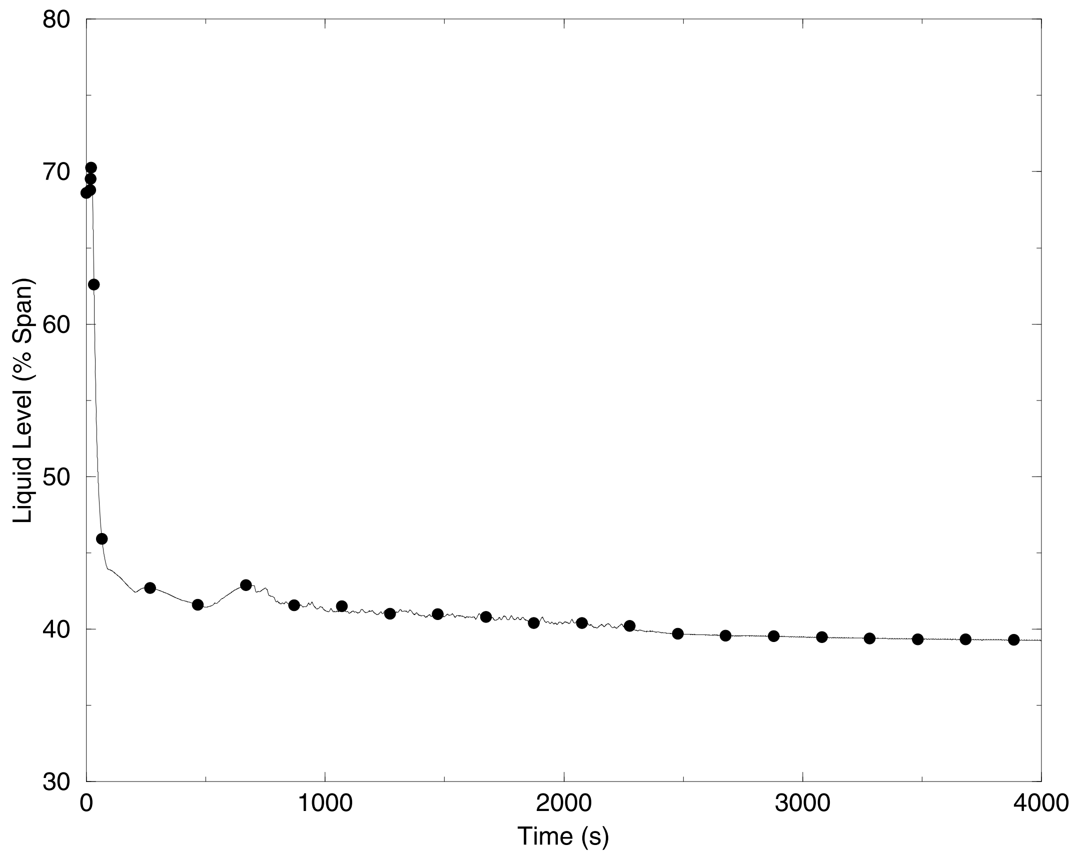


Figure 2.8.5.2.3-4
Loss of Normal Feedwater Flow
RCS Loop Temperatures

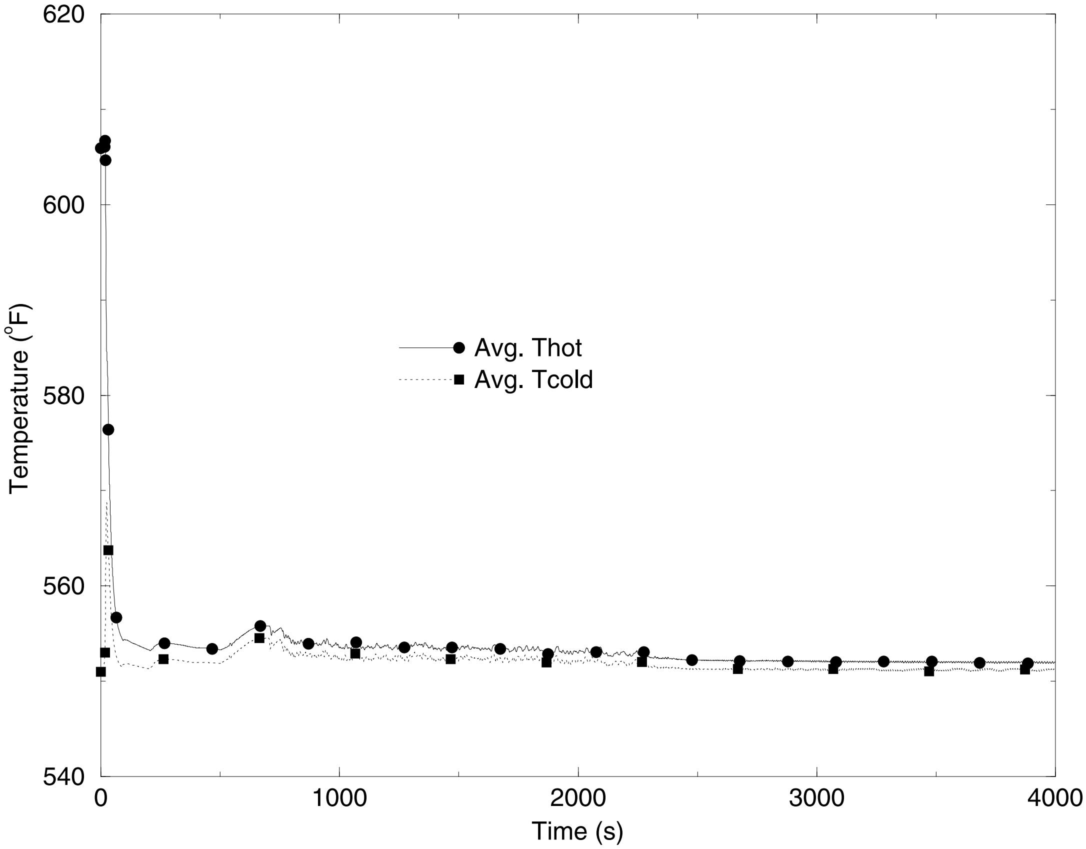


Figure 2.8.5.2.3-5
Loss of Normal Feedwater Flow
RCS Total Loop Flow Rate

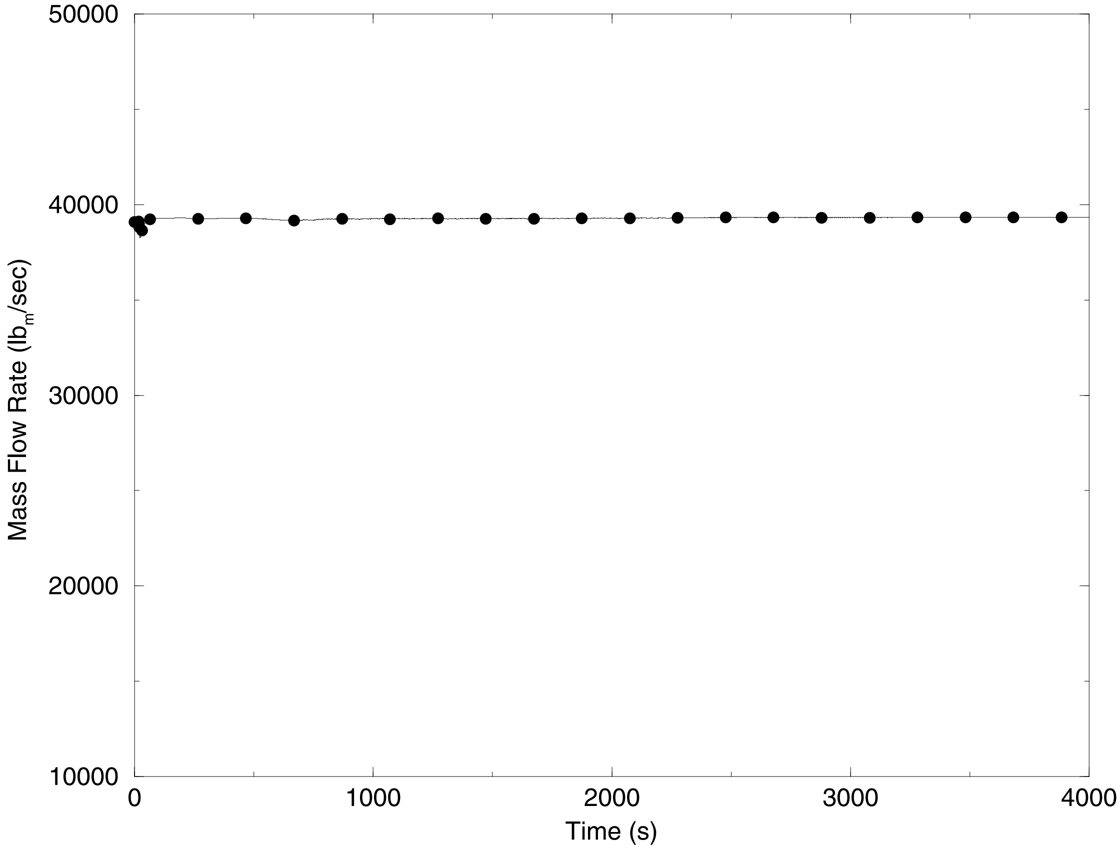


Figure 2.8.5.2.3-6
Loss of Normal Feedwater Flow
Steam Generator Pressures

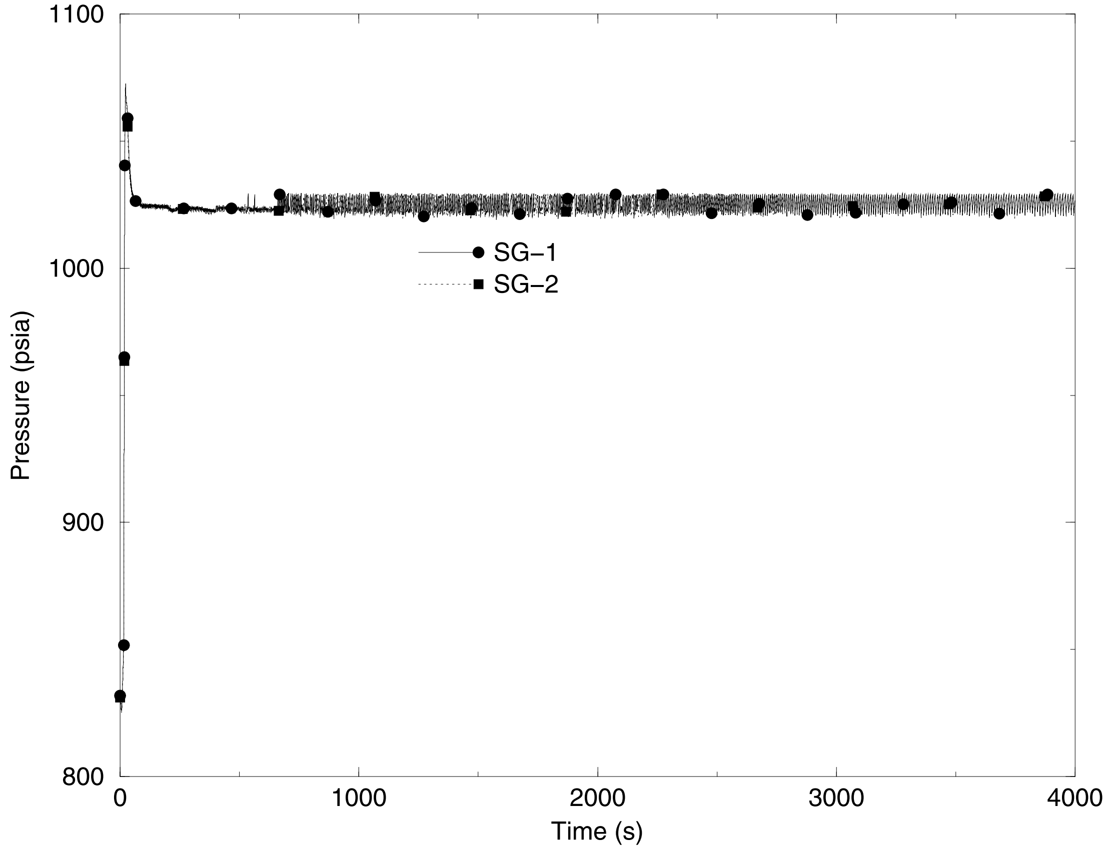


Figure 2.8.5.2.3-7
Loss of Normal Feedwater Flow
Auxiliary Feedwater Flow Rates

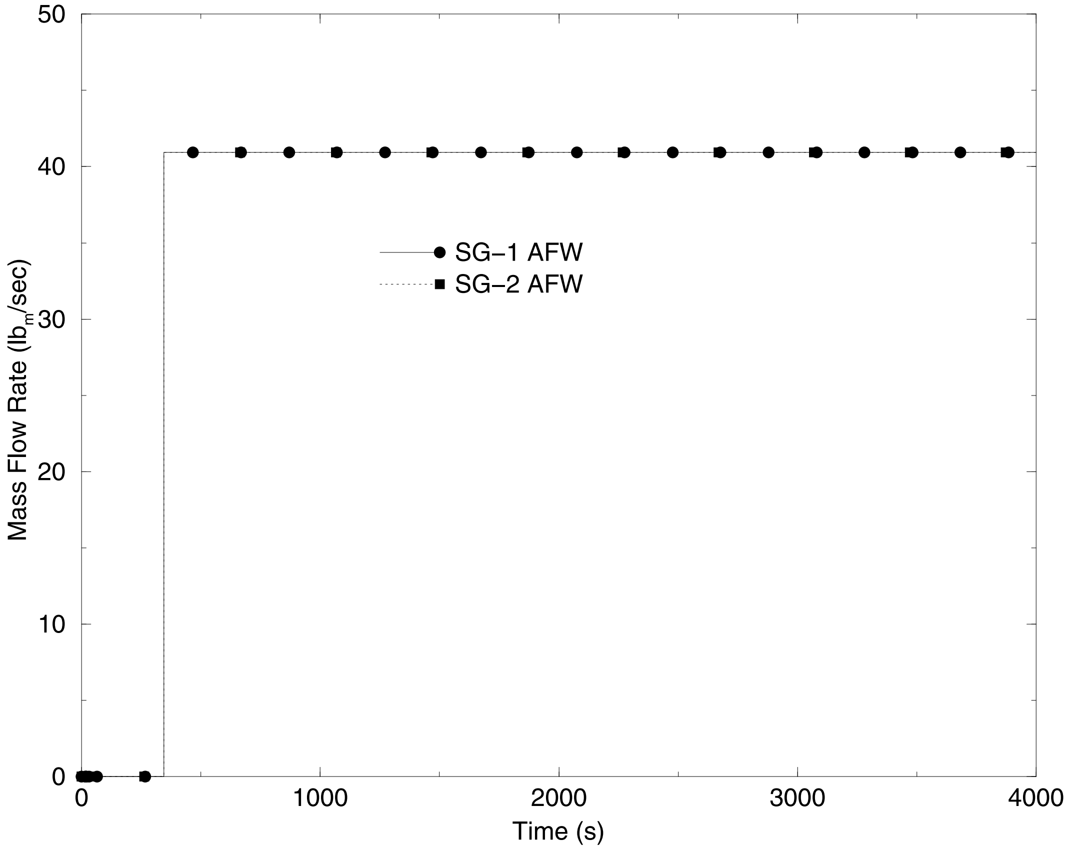


**Figure 2.8.5.2.3-8
Loss of Normal Feedwater Flow
Steam Generator Blowdown Flow Rates**

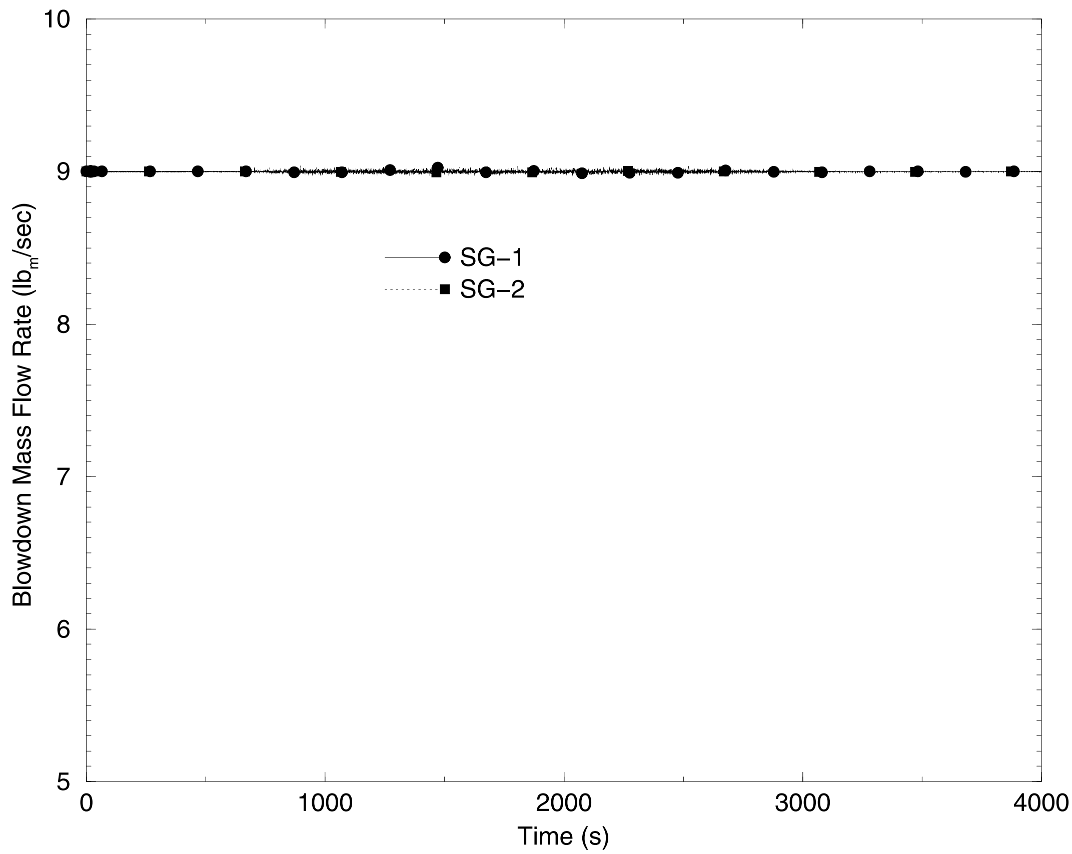
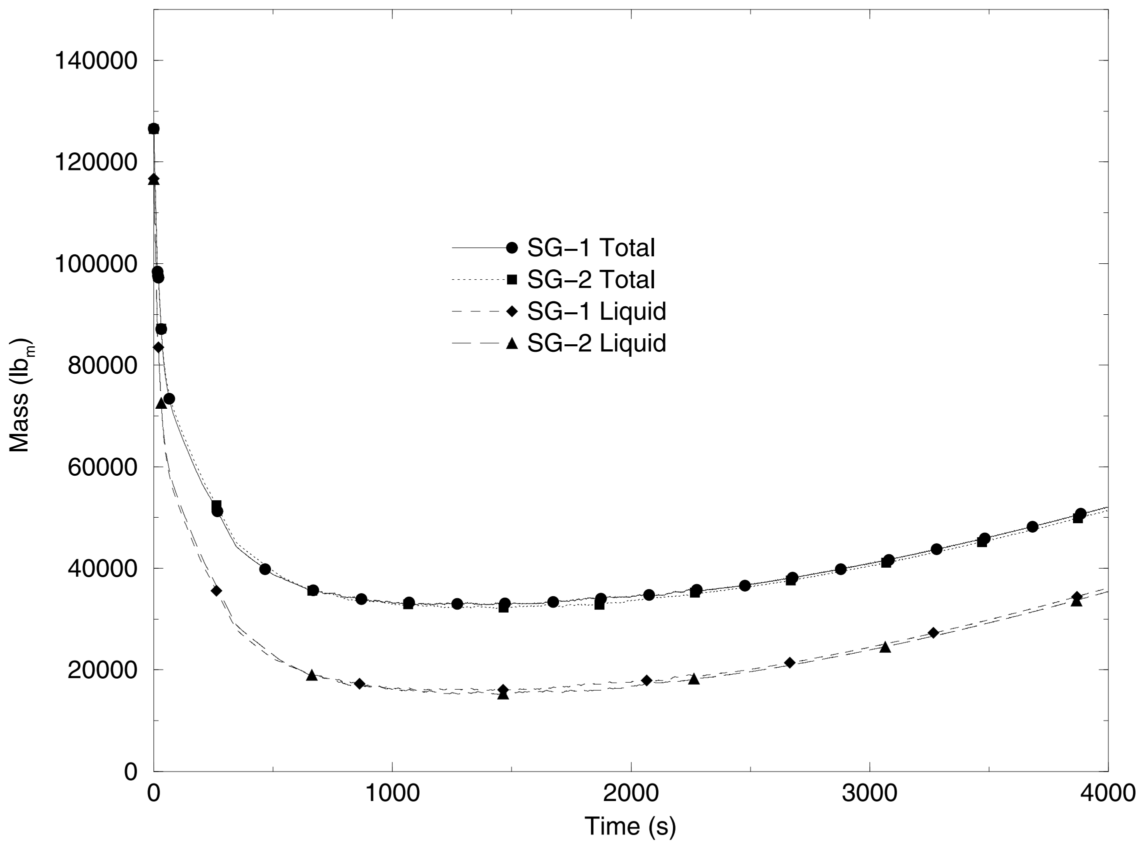


Figure 2.8.5.2.3-9
Loss of Normal Feedwater Flow
Steam Generator Masses



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 break 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.

FPL's 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,
- Operator actions, and
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the 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;
- GDC-35, insofar as it requires the RCS and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in SRP Section 15.2.8 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of control element assemblies (CEAs) and soluble boron 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.

During an accident, the safety injection system functions to inject concentrated boric acid into the RCS for long term and short 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 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 ECCS is discussed in detail in UFSAR Sections 6.3.2 and 6.3.3. The system is designed to prevent fuel and clad damage that would interfere with the emergency core cooling function for the full spectrum of break sizes, and to limit metal-water reaction. Each of the subsystems is fully redundant. The ECCS design satisfies the criteria specified in 10 CFR 50, Appendix K.

Discussion of feedwater system pipe breaks as a cooldown event is provided in UFSAR Section 15.2.8. Feedwater system pipe breaks as a heat up event is not a part of the St. Lucie Unit 1 licensing basis and thus, is not analyzed in the UFSAR.

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.

2.8.5.2.4.2 Technical Evaluation

This event is defined as a cooldown event in the current licensing basis for the plant, as described in the UFSAR. As such, the feedwater pipe break event is bounded by the steam system piping failures inside and outside of containment event (LR Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment). This is because the area for flow in a broken feedwater pipe (or feedwater ring nozzle area) is less than the assumed break (full steam line area) in the main steam line break event, and the enthalpy of the break flow is less for a feedwater line break than all steam flow, which is assumed for the main steam line break event. A smaller break area and smaller break enthalpy for the feedwater pipe break event results in a less severe primary system cooldown compared to a main steam line break event, and thus, a smaller challenge of return to power or loss of shutdown margin.

As explained above, in the St. Lucie Unit 1 licensing basis, the feedwater line break (FWLB) event is defined as a cooldown event that is bounded by the main steam line break (MSLB) event. The key system, subsequent to reactor trip, for mitigating the post-scram MSLB event is the Safety Injection System, which injects boron into the RCS to arrest the post-scram return-to-power (See LR Section 2.8.5.1.2). The same mitigating systems apply to both MSLB and FWLB.

2.8.5.2.4.2.1 Evaluation of 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.

2.8.5.2.4.3 Conclusions

FPL has reviewed the feedwater system pipe break event and concludes that the event has been adequately addressed for operation of the plant at the proposed power level. 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, and abundant core cooling will be provided. Based on this, FPL concludes that the plant will continue to meet its current licensing basis with respect to the requirements of GDCs -27, and -35 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to feedwater system pipe breaks.

2.8.5.2.5 Asymmetric Steam Generator Transient

2.8.5.2.5.1 Regulatory Evaluation

NRC review standard RS-001, Rev. 0 does not explicitly call out Standard Review Plan (SRP) or other guidance documentation for current or post-uprate license basis reviews pertaining to transients resulting from the malfunction of one steam generator (SG). The asymmetric steam generator transient (ASGT) is analyzed to confirm that departure from nucleate boiling ratio (DNBR) and fuel centerline melt (FCM) 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 reactor coolant system (RCS) pressurization events. Reactor protection and safety systems are actuated to mitigate such events.

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:

- 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;
- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC pertaining to the ASGT 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and anticipated operational occurrences are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of 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 control element assemblies (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 AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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 acceptable fuel design limits are not exceeded. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of ASGT transients is provided in UFSAR Section 15.2.2.

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

Transients resulting from the malfunction of one SG are characterized by increased load in one SG and decreased load in the other SG. This leads to an asymmetric core inlet coolant temperature, which when combined with a negative moderator temperature coefficient (MTC) results in an increase in power. The asymmetric core inlet coolant temperature may also lead to augmented radial peaking, thus potentially challenging the departure from nucleate boiling (DNB) and FCM SAFDLs.

Section 15.2.2 of the UFSAR identifies four asymmetric events which are initiated by the malfunction of one SG: loss of load to one SG, excess load to one SG, loss of feedwater to one SG, and excess feedwater to one SG.

2.8.5.2.5.2.1 Loss of Load to One Steam Generator

2.8.5.2.5.2.1.1 Introduction

A loss of load to one SG (single MSIV closure) event is initiated by the inadvertent closure of a single MSIV. Upon the loss of load to the affected SG, its pressure and temperature rapidly increase, which causes a heatup of its associated RCS loop. Due to the loss of load to the affected SG and continued full steam demand, there is an increase in steam flow from the unaffected SG. The increased steam flow from the unaffected SG causes a cooldown of its associated RCS loop. The result is asymmetry in the coolant temperatures entering the core from the affected and unaffected RCS loops. An increase in core power occurs with the potential for augmented radial peaking. This event was analyzed for the EPU.

2.8.5.2.5.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The input parameters and biasing were consistent with the approved Reference 1 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions - This event was assumed to initiate from hot full power (HFP) conditions with a maximum core inlet temperature and TS minimum RCS flow. This set of conditions minimizes the initial margin to DNB.
- Reactivity Feedback - The reactivity feedback coefficients were biased according to the approved methodology. The coolant temperature from the affected loop actually increases faster than the coolant temperature from the unaffected loop decreases. However, the decreasing coolant temperature from the unaffected loop combined with a large negative end of cycle (EOC) MTC will have a more dominant effect on core power than the increasing coolant temperature from affected loop combined with a positive TS/core operating limits report (COLR) MTC.
- Reactor Protection System (RPS) Trips and Delays - The event is primarily protected by the asymmetric SG pressure trip (ASGPT). The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion was delayed to account for the CEA holding coil delay time.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analysesprovides the SGTP level supported by the analyses.

The acceptance criteria for this event are:

- The pressures in the RCS and main steam system should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

Peak primary and secondary side pressures are bounded by the loss of load event (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum) because the unaffected SG for the loss of load to one SG event takes part of the load from the affected SG. The SAFDL criterion is met by assuring that the minimum calculated DNBR is not less than the 95/95 DNB correlation limit.

2.8.5.2.5.2.1.3 Description of Analyses and Evaluations

For the EPU, detailed analyses were performed with approved non-LOCA methodology given in Reference 1. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 2), which was used to calculate the minimum departure from nucleate boiling ratio (MDNBR), using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 3).

2.8.5.2.5.2.1.4 Results

The sequence of events is summarized in LR Table 2.8.5.2.5-1. Results are given in LR Table 2.8.5.2.5-2. Statepoints for the DNB analyses were chosen at or near the time of peak heat flux. The limiting MDNBR was calculated to be above the 95/95 CHF correlation limit.

Key system parameters illustrating the transient are presented in LR Figures 2.8.5.2.5-1 through 2.8.5.2.5-10. LR Figure 2.8.5.2.5-1 shows the reactor power as a function of time. LR Figures 2.8.5.2.5-2 through 2.8.5.2.5-10 show the core power based on rod surface heat flux, the pressurizer pressure, the pressurizer liquid level, the RCS loop temperatures, the total RCS flow rate, the SG pressures, the steam and feedwater flow rates, the reactivity feedback, and the main steam safety valve (MSSV) flow rates, respectively.

2.8.5.2.5.2.2 Excess Load to One Steam Generator

An excess load to one SG (e.g., inadvertent opening of a single MSSV) event causes a decrease in the cold leg temperature of the affected loop, which results in a small temperature and power tilt across the core. With a most-negative MTC, this will cause a small increase in core power and radial peaking. The event, however, does not result in a particularly large asymmetry in steam flow from each SG. This event was analyzed for EPU and is documented in LR Section 2.8.5.1.1, Decrease In Feedwater Enthalpy, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve.

2.8.5.2.5.2.3 Loss of Feedwater to One Steam Generator

A loss of feedwater to one SG event is initiated at HFP by a malfunction in one of the feedwater controllers, which instantaneously shuts the feedwater regulator valve to one SG. The loss of feedwater causes the temperature and pressure to increase in the affected SG due to the decreasing SG level. The core inlet temperature from both loops increases due to the decrease in SG primary to secondary heat transfer. However, a slight asymmetry in core inlet temperature develops where the affected RCS loop increases in temperature faster than the unaffected RCS loop. The small core inlet temperature asymmetry will not cause a significant radial power tilt. The small increase in core inlet temperature, combined with a TS positive MTC, will result in an increase in core power. However, the increase in core power will be less than that for the loss of feedwater flow event (LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow), since the increase in core inlet temperature will be less. This event is thus bounded by the loss of feedwater flow (loss of feedwater to both SGs) event.

2.8.5.2.5.2.4 Excess Feedwater to One Steam Generator

An excess feedwater to one SG, initiated at HFP, is caused by the complete opening of a single feedwater control valve, since the two feedwater control valves and their control are independent. The increased main feedwater (MFW) flow to the affected SG, when combined with the recirculation flow, results in a small decrease in the MFW temperature. This results in an increase in heat transfer along the tubes of the affected SG and a small cooldown of the affected RCS cold legs. Also, increased MFW flow to the affected SG results in a small decrease in pressure and temperature in the affected SG, a small decrease in the vapor void fraction at the exit of the boiler region, and a small decrease in steam flow to the turbine. Since the two SGs are in communication, the pressure and temperature in the unaffected SG also experience a small decrease. The decrease in the unaffected SG temperature (along with a slight increase in steam flow) causes a small cooldown of the unaffected RCS cold legs, which is less than that for the affected RCS loop. With a slightly reduced steam flow rate from the affected SG, the unaffected SG “picks up” the lost load with a slightly increased steam flow rate. The resulting asymmetry in the RCS cold leg temperatures between the affected and unaffected loops is very small. There would be no significant augmented peaking due to this slight asymmetry in RCS cold leg temperatures. Since there is no significant asymmetry in RCS cold leg coolant temperatures for this event, and since the decrease in RCS coolant temperatures due to increased MFW to one SG is much smaller for this event than for the excess load event (LR Section 2.8.5.1.1, Decrease In Feedwater Enthalpy, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve), resulting in a much smaller positive moderator reactivity feedback, the excess feedwater to one SG event is bounded by the excess load event.

2.8.5.2.5.3 Evaluation of 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.

2.8.5.2.5.4 Conclusion

FPL has reviewed ASGT events described above and concludes that the analysis has 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 ASGT 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.

2.8.5.2.5.5 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.2.5-1
Loss of Load to One Steam Generator
Sequence of Events

Event	Time (sec.)
MSIV in loop 1 began to close	0.0
MSIV closed	6.9
Turbine throttle valve fully opened	7.2
Bank 1 MSSVs in loop 1 opened	7.8
ASGPT setpoint reached	8.7
VHPT setpoint reached (NI signal)	9.0
Reactor scram on VHPT (including trip response delay)(1)	9.4
CEA insertion begins	9.9
MDNBR	10.45
1. The analysis resulted in a near coincidental ASGPT and VHPT. The core power response for this event was conservatively modeled such that DNBR was conservatively predicted.	

Table 2.8.5.2.5-2
Loss of Load to One Steam Generator
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis	Limit
MDNBR	1.42	1.778	1.164
Note: The MDNBR for the previous analysis was calculated using CE methodology for a fuel design that is different than that supported by AREVA NP methods.			

Figure 2.8.5.2.5-1
Loss of Load to One Steam Generator
Reactor Power

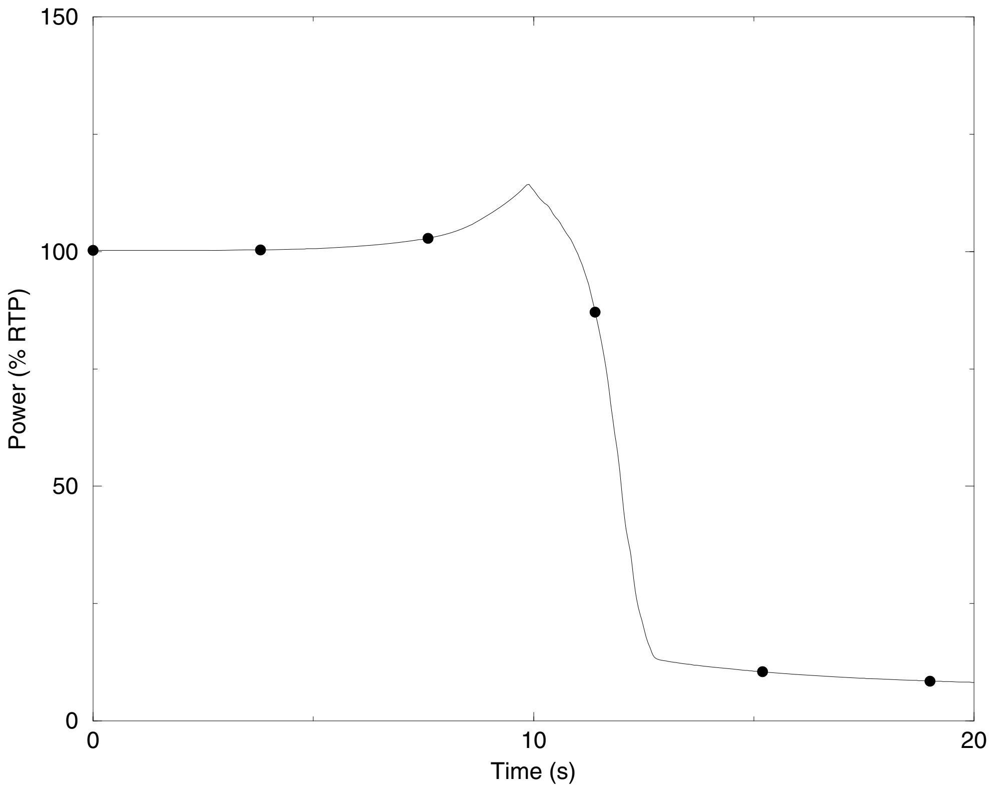


Figure 2.8.5.2.5-2
Loss of Load to One Steam Generator
Total Core Heat Flux Rate

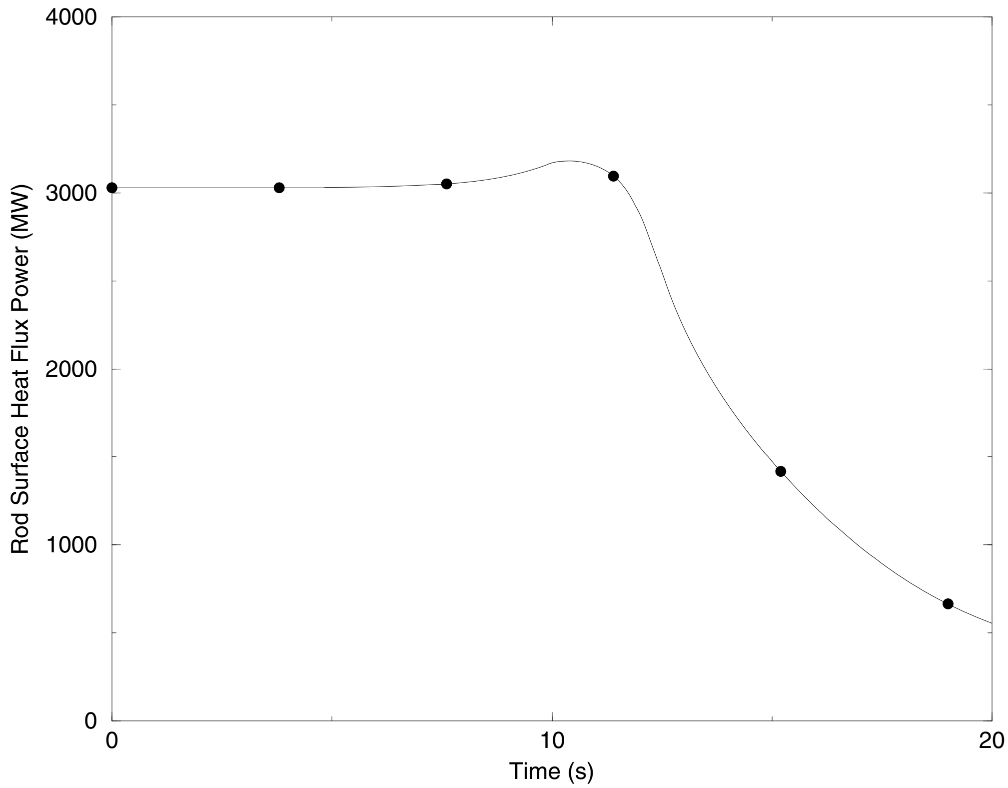


Figure 2.8.5.2.5-3
Loss of Load to One Steam Generator
Pressurizer Pressure

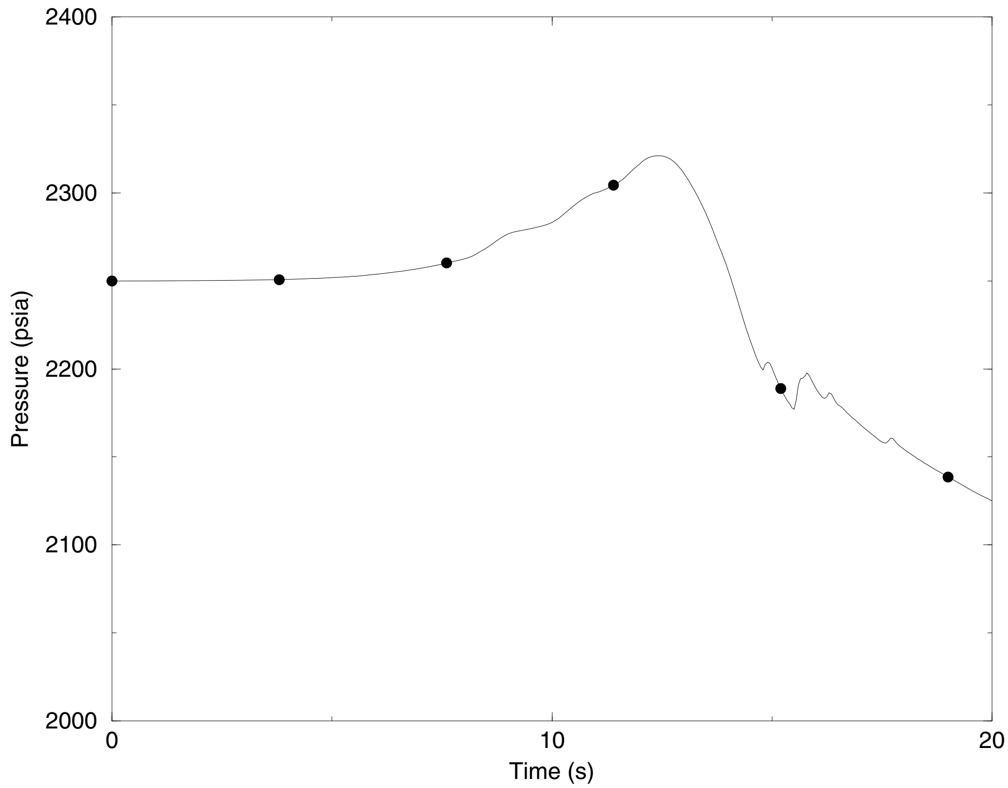


**Figure 2.8.5.2.5-4
Loss of Load to One Steam Generator
Pressurizer Liquid Level**

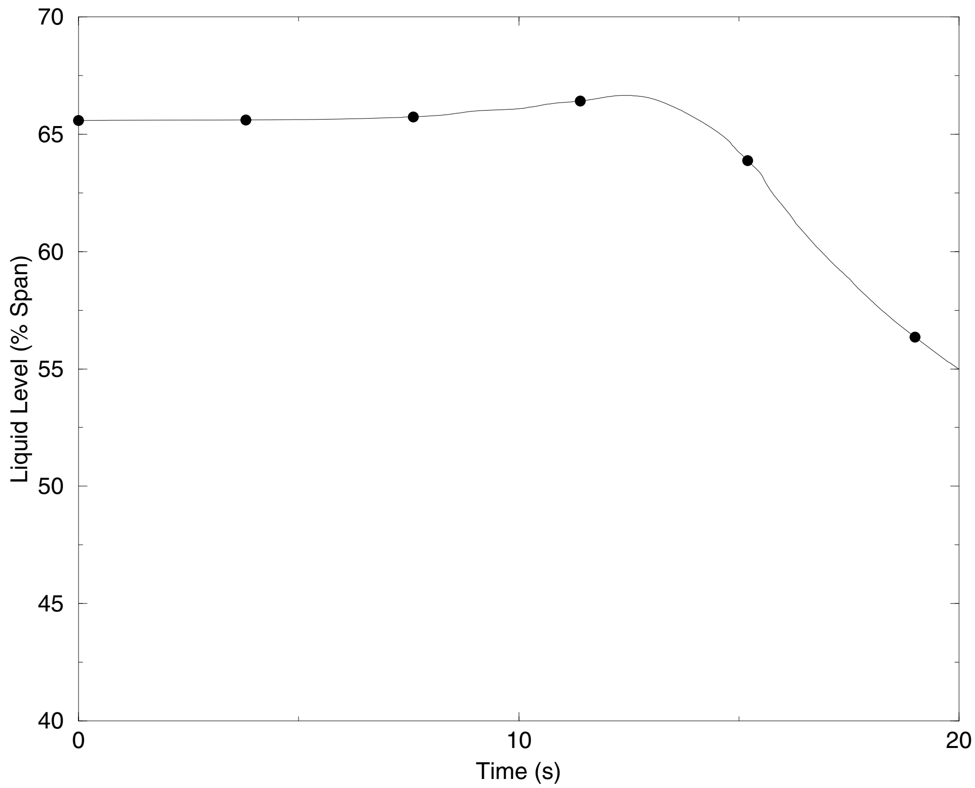


Figure 2.8.5.2.5-5
Loss of Load to One Steam Generator
RCS Loop Temperatures

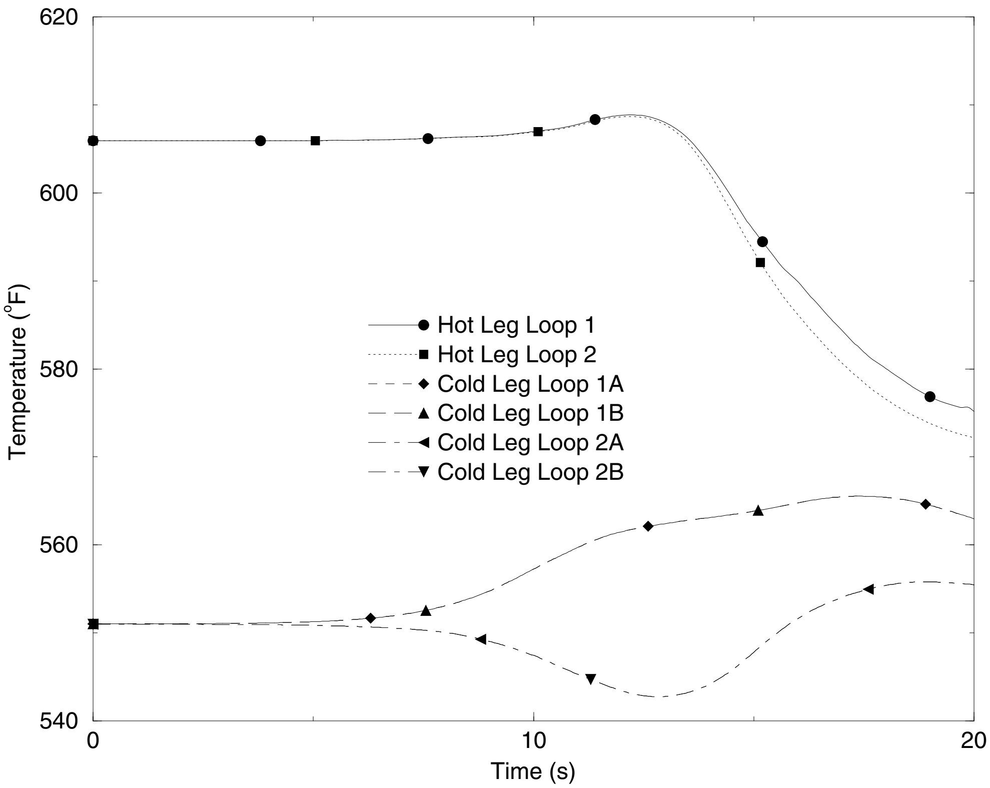


**Figure 2.8.5.2.5-6
Loss of Load to One Steam Generator
RCS Total Loop Flow Rate**

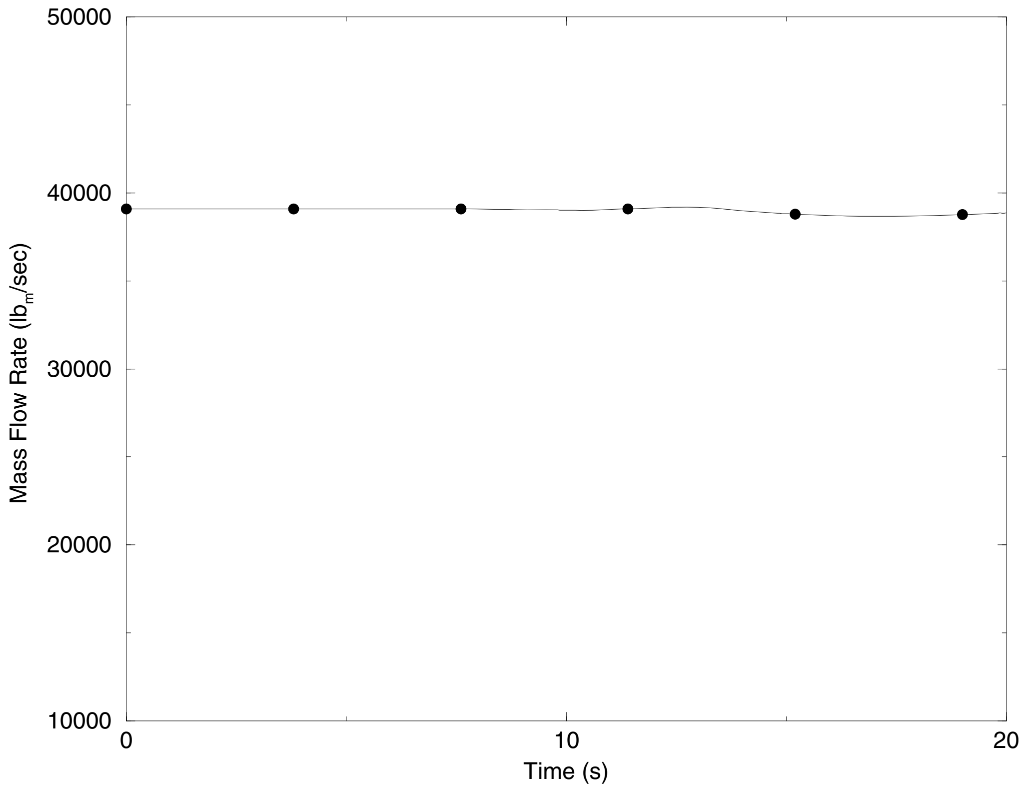


**Figure 2.8.5.2.5-7
Loss of Load to One Steam Generator
Steam Generator Pressures**

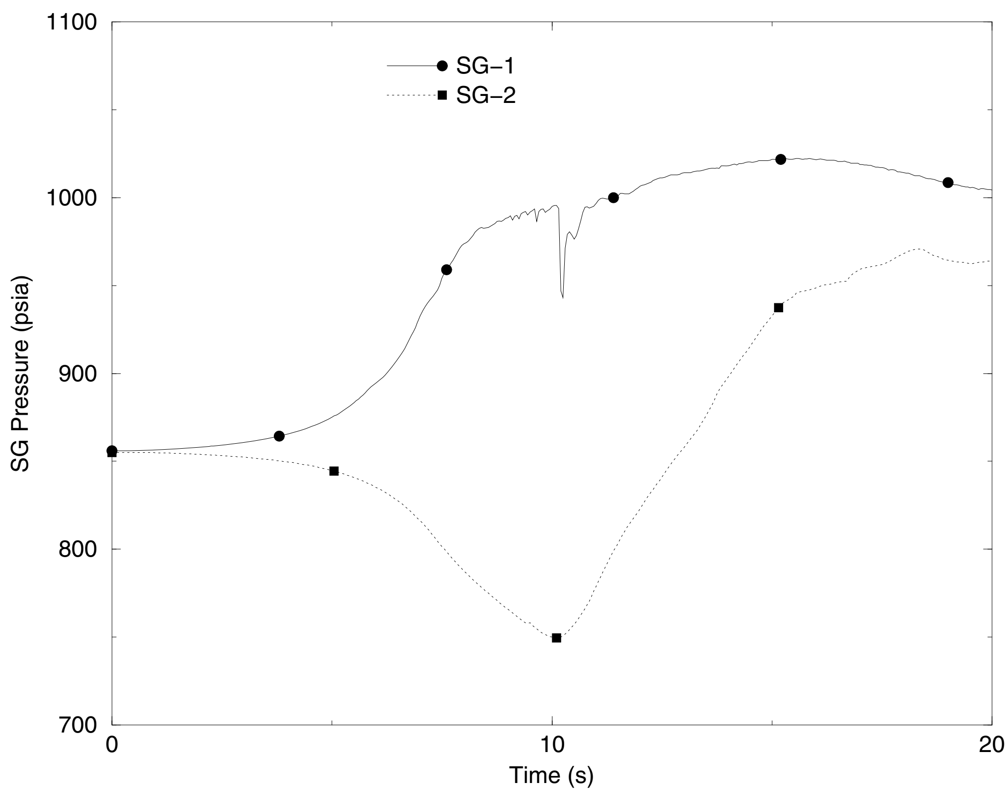


Figure 2.8.5.2.5-8
Loss of Load to One Steam Generator
Steam and Feedwater Flow Rates

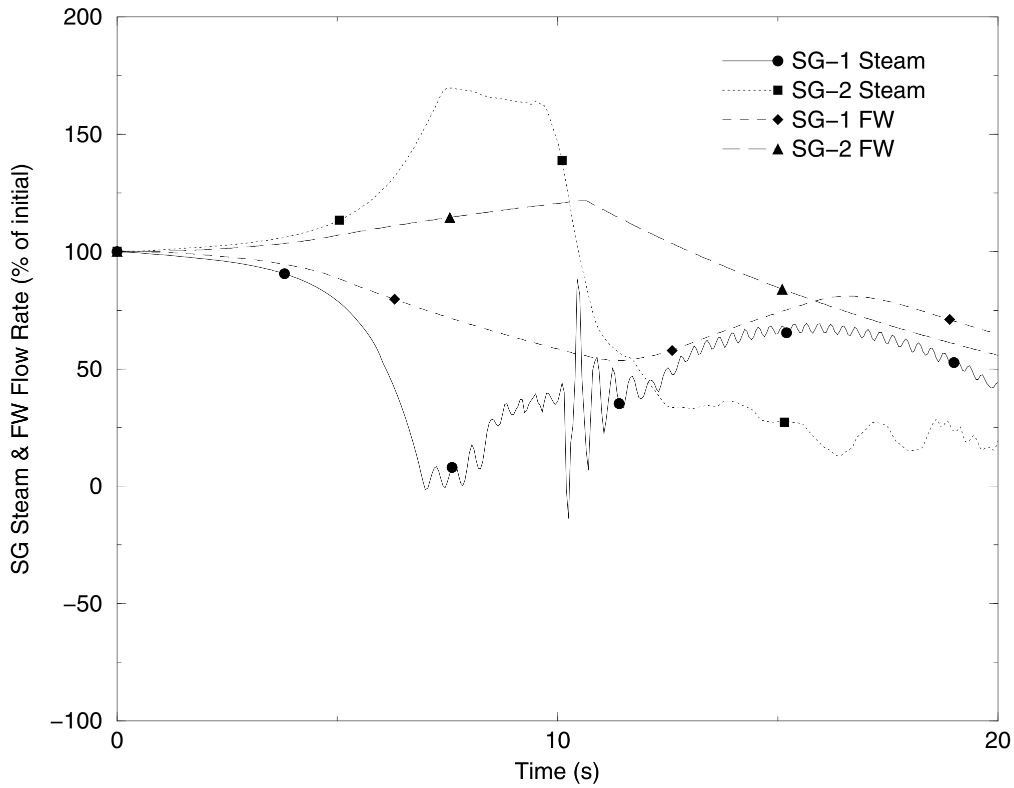


Figure 2.8.5.2.5-9
Loss of Load to One Steam Generator
Reactivity Feedback

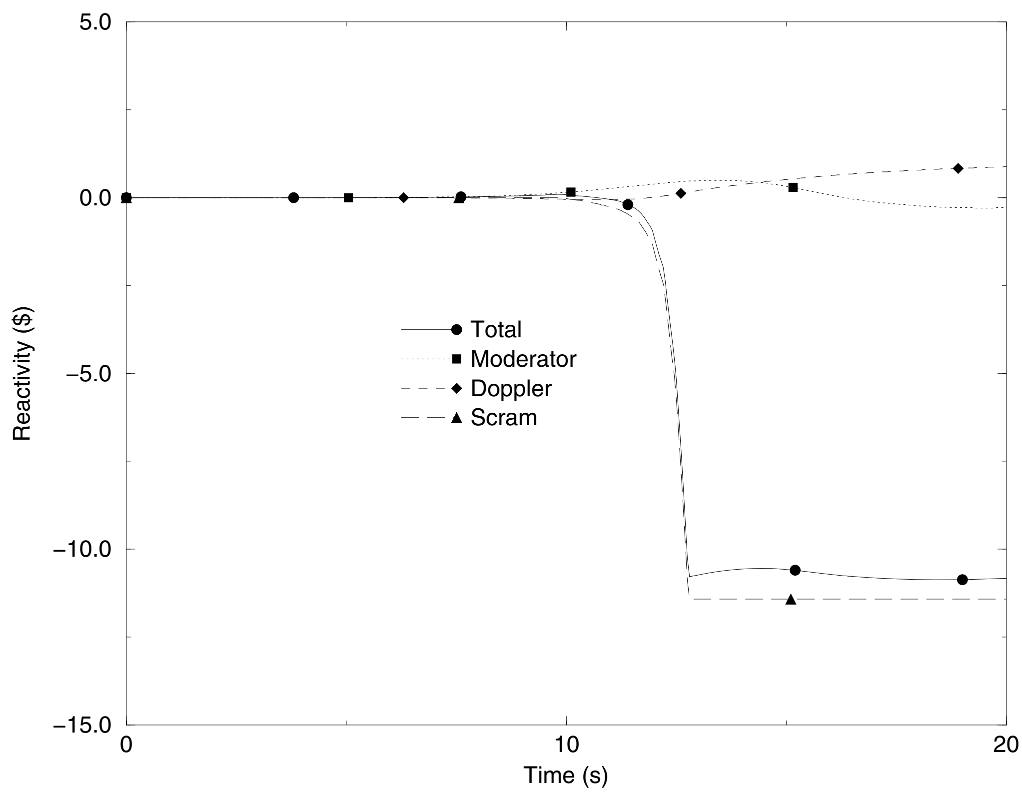
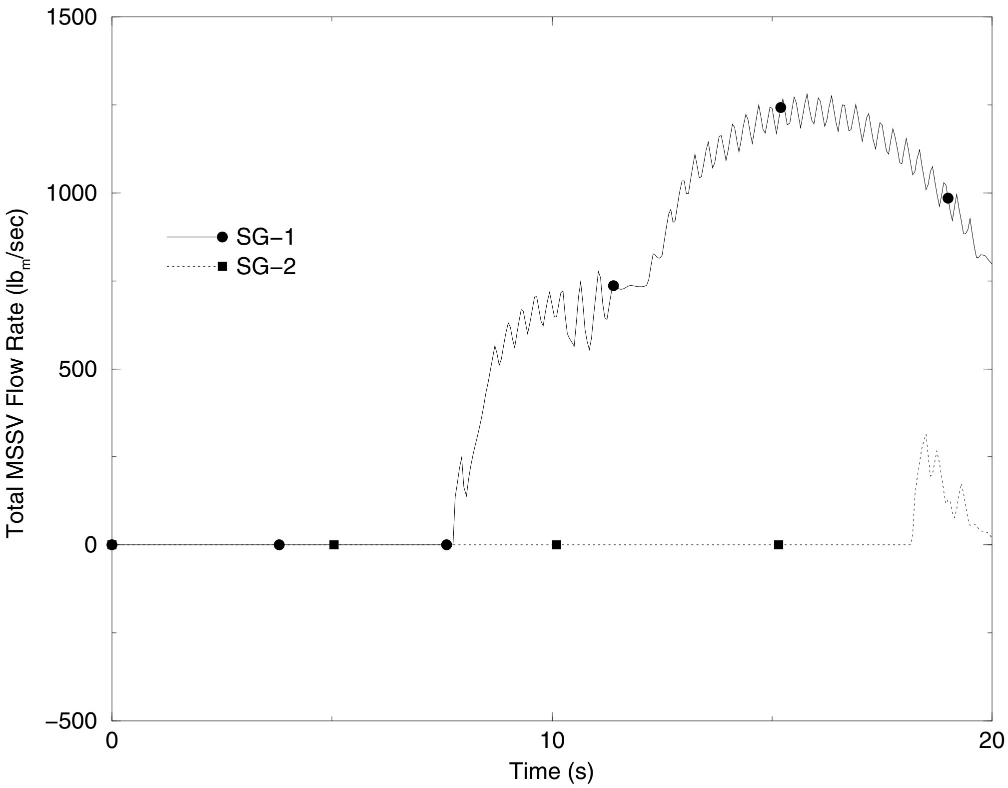


Figure 2.8.5.2.5-10
Loss of Load to One Steam Generator
MSSV Flow Rates



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.

FPL's 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:

- 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;
- 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 RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and Limiting Conditions for Operations (LCOs)), 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and anticipated operational occurrences are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain anticipated operational occurrences; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of 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 control element assemblies (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 anticipated operational occurrences, specified acceptable fuel design limits are not exceeded. Refer to UFSAR Section 4.2.3. 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 acceptable fuel design limits are not exceeded. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the loss of reactor coolant flow event is provided in UFSAR Section 15.2.5.

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-coolant flow event may result from a loss of electrical power to one or more of the four reactor coolant pumps (RCPs). A partial loss-of-coolant flow event is a less severe transient than the complete loss-of-coolant flow event due to the smaller flow reduction. The most limiting event is a loss of power to all four RCPs (four-pump coastdown).

A decrease in reactor coolant flow while a plant is at power results in degraded core heat transfer, reduction in departure from nucleate boiling (DNB) margin. The primary concern with this event is the challenge to the DNB SAFDL. The fuel centerline melt SAFDL is not challenged, since there is no significant increase in core power for this event. The reduction in primary system flow and the associated increase in core coolant temperatures, result in a reduction in departure from nucleate boiling ratio (DNBR) margin. The increasing primary system coolant temperatures also result in expansion of the primary coolant volume, causing an in-surge into the pressurizer and an increase in the pressure of the primary system. However, the pressure increase is small and the pressure limits are not challenged by this event. For St. Lucie Unit 1, this event is analyzed to verify the reactor protection system (RPS) low flow trip setpoint in combination with the TS/core operating limits report (COLR) LCOs, namely the initial core power level, the maximum initial core inlet temperature, the minimum initial RCS flow rate, and the axial shape index (ASI) limits.

2.8.5.3.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event were consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – Hot full power (HFP) initial conditions, maximum TS core inlet temperature and minimum TS RCS flow rate were modeled in order to minimize the initial margin to DNB.
- Reactivity Feedback – Since this event involves an increase in the core coolant temperature, the event was assumed to occur at beginning of cycle (BOC) with a maximum TS/COLR moderator temperature coefficient (MTC) at full power. However, this event occurs quickly and is generally not sensitive to neutronic parameters. A minimum HFP scram worth was used to conservatively prolong the degradation in flow while maintaining relatively high core power.
- Reactor Protection System Trips and Delays – The event is primarily protected by the low flow RPS trip. The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion is delayed to account for the CEA holding coil delay time.
- Gap Conductance – Gap conductance was set to a conservative BOC value to delay the transfer of heat from the fuel rod to the coolant allowing the primary system flow to decay further thus leading to a conservative prediction of DNBR.
- RCS Flow – The coastdown characteristics of the RCPs were the same as those in the current analysis and were previously benchmarked.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses, provides the SGTP level supported by the analyses.

For the loss-of-coolant flow event, the principally challenged acceptance criterion is:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

This criterion is met by assuring that the minimum calculated DNBR is not less than the 95/95 DNB correlation limit. Since this event does not involve a significant power transient or augmented peaking, the fuel centerline melt limit is not challenged.

2.8.5.3.1.2.3 Description of Analyses and Evaluations

Analyses supporting current plant operation were performed with the non-LOCA methodologies based on the PTSPWR2 code (Reference 1). For the EPU, detailed analyses were performed with approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of minimum departure from nucleate boiling ratio (MDNBR). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 3), which was used to calculate the MDNBR using the high thermal performance (HTP) critical heat flux (CHF) correlation (Reference 5). The loss-of-coolant flow event was also addressed as part of the DNB LCO statistical setpoint analyses (LR Section 2.8.5.0, Accident and Transient Analyses) using the Reference 4 methodology.

A single case was analyzed at BOC HFP initial conditions, maximum TS core inlet temperature and minimum TS RCS flow rate. The factors affecting scram time were biased using conservative trip signal delay and holding coil delay times to produce the most significant challenge to the DNB limit.

2.8.5.3.1.2.4 Evaluation of 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 sequence of events is given in LR Table 2.8.5.3.1-1. Results are given in LR Table 2.8.5.3.1-2. Statepoints for the DNB analyses were chosen at or near the time of the most adverse combination of power and flow. The MDNBR with deterministically applied uncertainties was calculated for the extended power uprate (EPU) to be greater than the 95/95 limit. Statistical evaluation of this event is performed as part of the DNB LCO analyses (LR Section 2.8.5.0, Accident and Transient Analyses).

Plots of key system parameters are shown in LR Figures 2.8.5.3.1-1 through 2.8.5.3.1-6. LR Figure 2.8.5.3.1-1 shows the reactor power as a function of time. LR Figure 2.8.5.3.1-2 shows the core power based on rod surface heat flux. LR Figure 2.8.5.3.1-3 shows pressurizer pressure. LR Figure 2.8.5.3.1-4 shows RCS loop temperatures. LR Figure 2.8.5.3.1-5 shows the total RCS flow rate. LR Figure 2.8.5.3.1-6 shows the reactivity feedback.

2.8.5.3.1.3 Conclusion

FPL has reviewed the analysis of the decrease in reactor coolant flow event and concludes the analysis adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. FPL further concludes that the analysis 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 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 reactor coolant flow event.

2.8.5.3.1.4 References

1. ANF-84-73(P)(A), Revision 5, Appendix B, & Supplements 1 and 2, Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events, Advanced Nuclear Fuels Corporation, October 1990.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. EMF-1961(P)(A), Revision 0, Statistical/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

5. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.3.1-1
Loss of Forced Coolant Flow
Sequence of Events

Event	Time (sec)
Pump coastdown initiates	0.0
Low RCS flow trip setpoint reached	1.008
Reactor scram on low RCS flow rate (including trip response delay)	2.033
CEA insertion begins	2.533
Peak core power	2.54
MDNBR	3.75
CEAs fully inserted	5.43
Peak pressurizer pressure	5.59

Table 2.8.5.3.1-2
Loss of Forced Coolant Flow
Results

Criterion	EPU Analysis	Limit
MDNBR	1.319	1.164

Figure 2.8.5.3.1-1
Loss of Forced Coolant Flow
Reactor Power

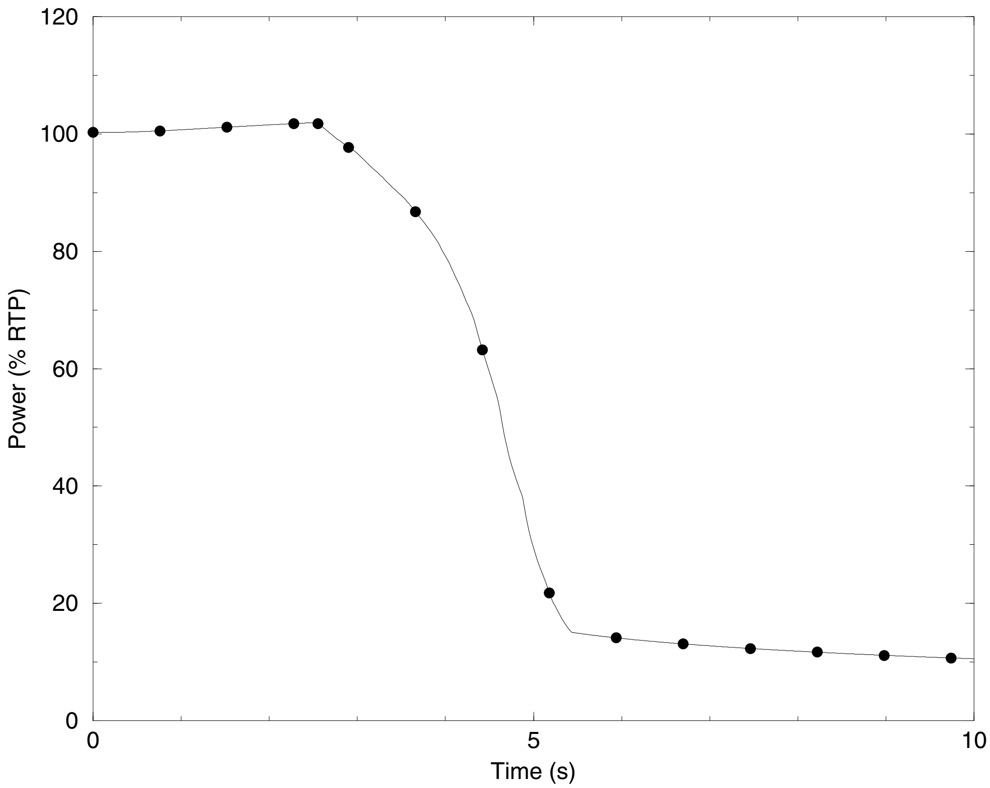


**Figure 2.8.5.3.1-2
Loss of Forced Coolant Flow
Total Core Heat Flux Power**

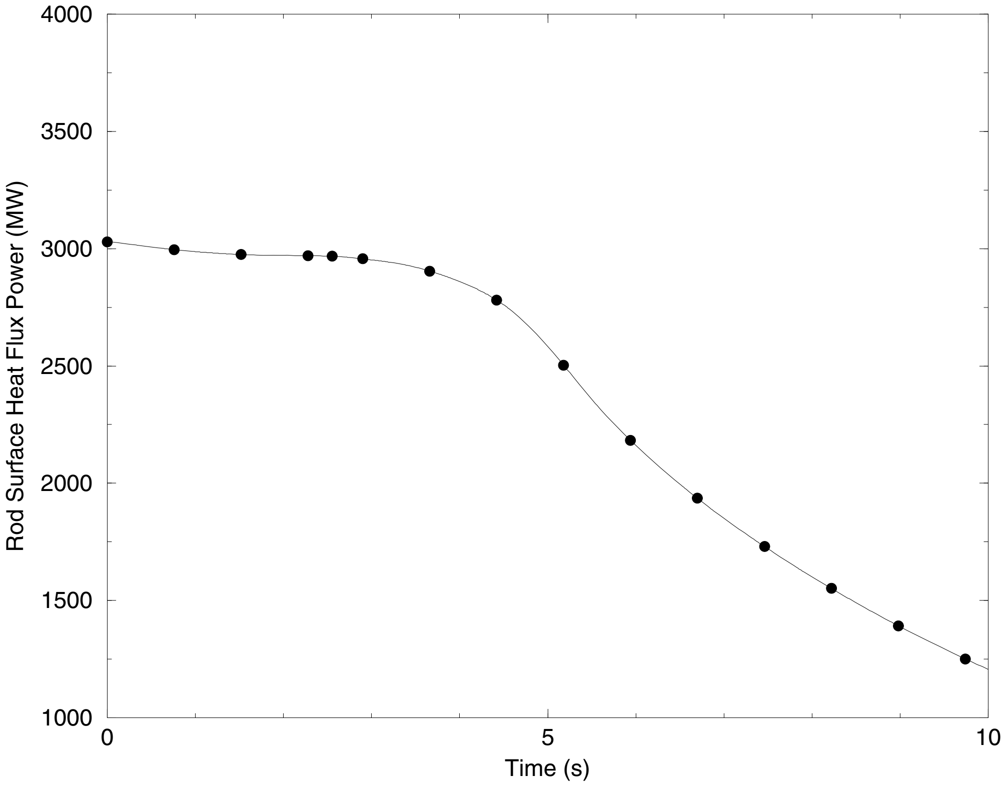


Figure 2.8.5.3.1-3
Loss of Forced Coolant Flow
Pressurizer Pressure

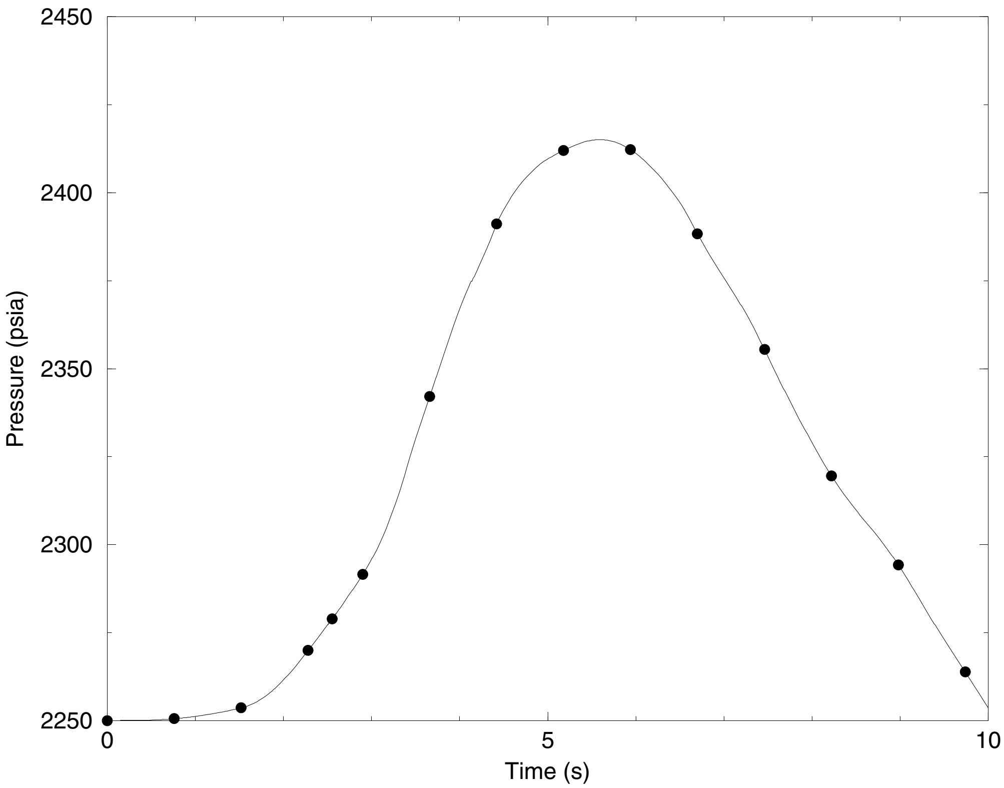


Figure 2.8.5.3.1-4
Loss of Forced Coolant Flow
RCS Loop Temperatures

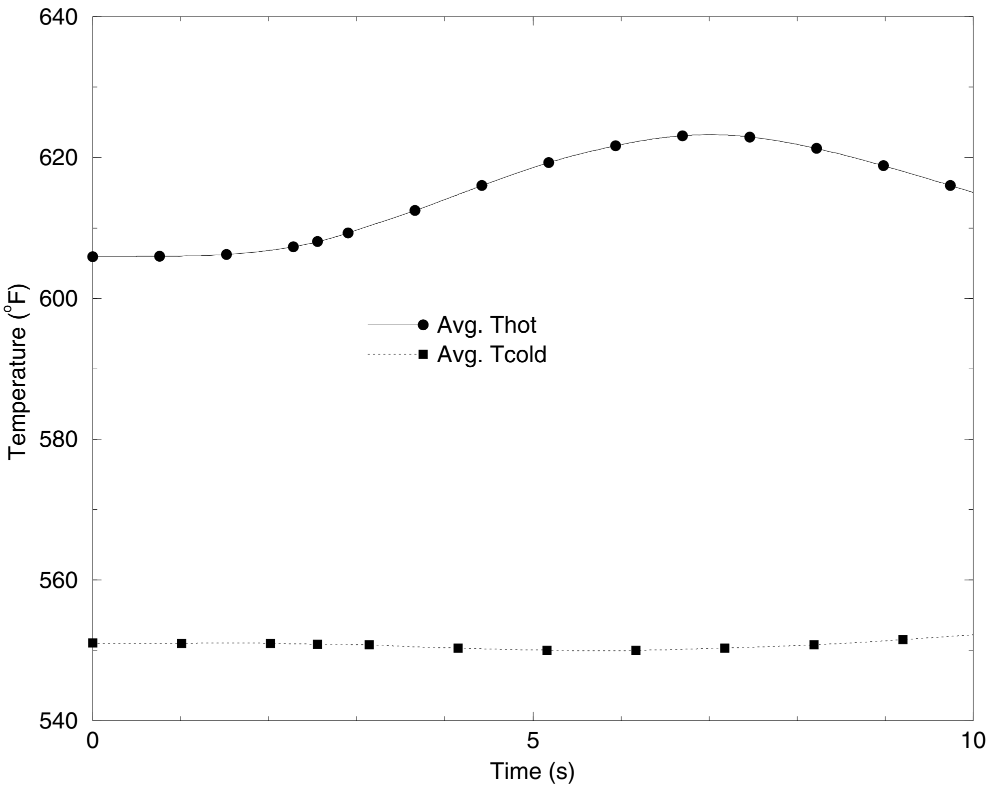


Figure 2.8.5.3.1-5
Loss of Forced Coolant Flow
RCS Total Loop Flow Rate

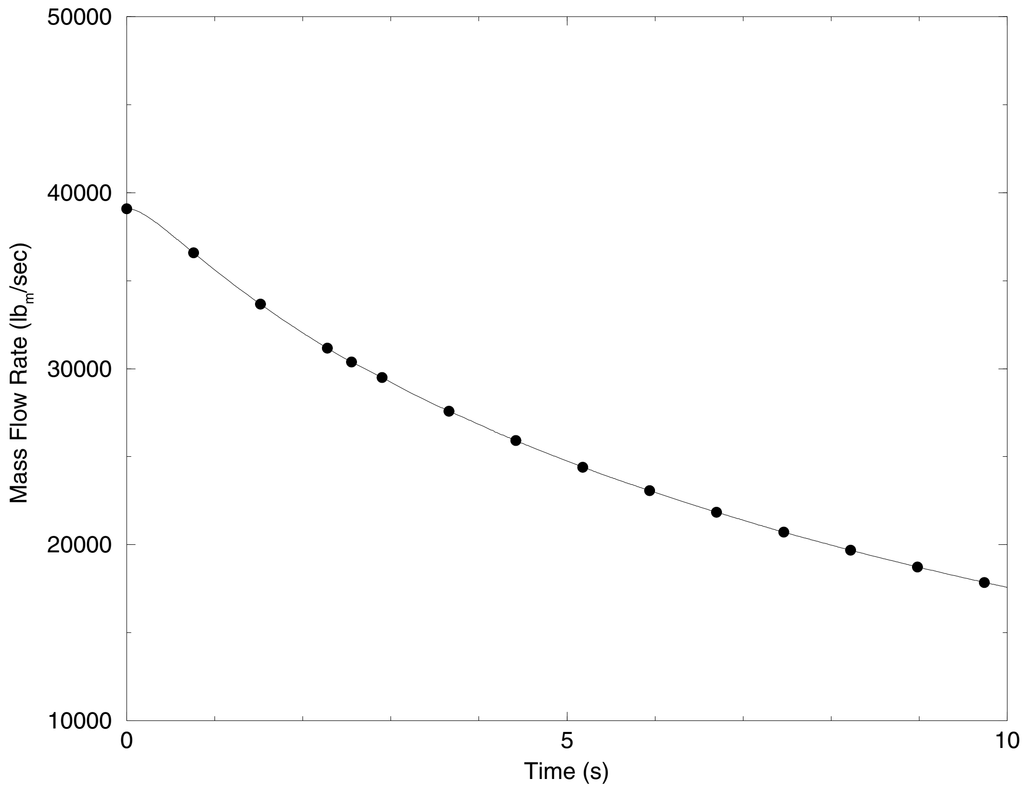
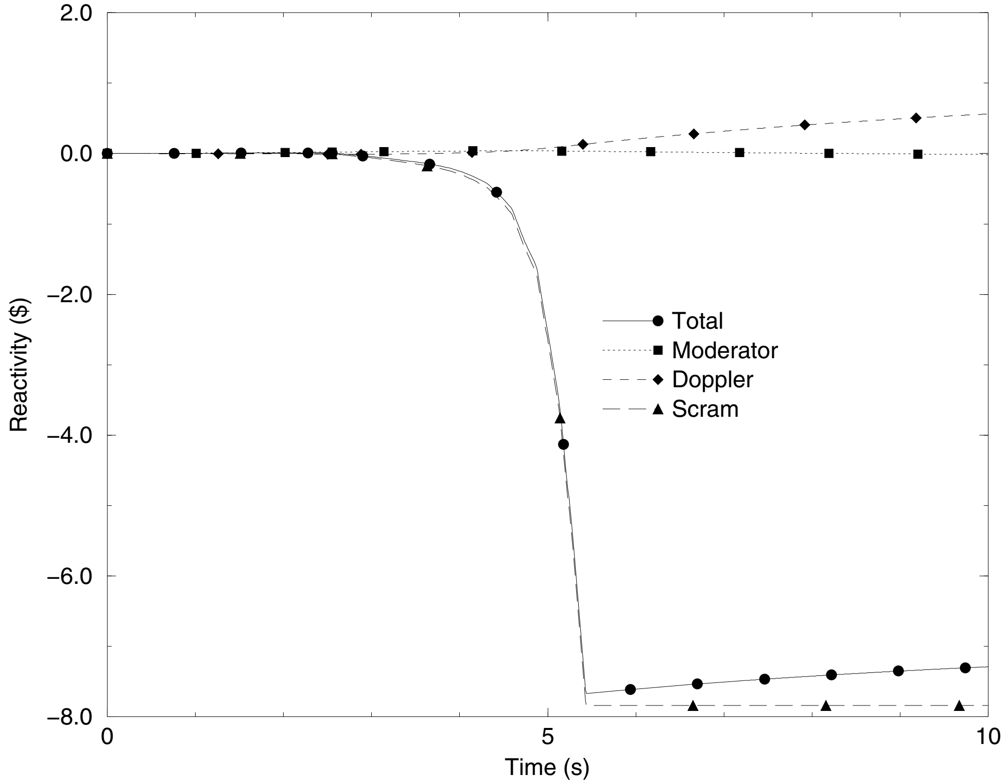


Figure 2.8.5.3.1-6
Loss of Forced Coolant Flow
Reactivity Feedback



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.

An evaluation has been performed that demonstrates that the effects of the RCP rotor seizure are more limiting than the effects of the RCP shaft break. Therefore the focus of this LR section pertains to the RCP rotor seizure event. RCP Shaft break is not part of the St. Lucie Unit 1 current licensing basis.

FPL's 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:

- 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.

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.

Although RCP shaft break event is not a part of the current licensing basis for St. Lucie Unit 1, it remains bounded by the RCP rotor seizure event. The RCP rotor seizure results in a rapid reduction in the reactor coolant flow as compared to a shaft break event, because the fixed rotor causes a greater flow resistance than a free-spinning impeller. The faster flow decrease in a rotor seizer event also results in an early flow reversal in the affected loop, with no credit taken for the anti-reverse rotational device. As the transient progresses, the flow to the core will be less in the shaft break case than the rotor seizer case during the periods of reverse flow in the affected loop. However, the limiting conditions occur early in the transient dominated by the faster flow reduction and an earlier flow reversal in the affected loop. Consequently, the results of rotor seizer event bound those of shaft break event.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC for the RCP rotor seizure 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of control element assemblies (CEAs) and soluble boron 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 long term and short term cooling and for reactivity control. Details of the system are given in 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 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 minimum value. The CEAs are divided into shutdown groups and regulating groups. Administrative procedures and interlocks ensure that only one group is withdrawn at a time, and that 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 7.1.1.

The maximum rate of reactivity addition which may be produced by the CVCS is too low to induce any significant pressure forces which might degrade the RCPB leak tightness integrity or disturb the reactor vessel intervals. UFSAR Section 9.3.4 describes the design bases of the CVCS.

The RCPB described in UFSAR Chapter 5 and the reactor vessel internals described in USFAR Chapter 4 can 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 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 constructed in accordance with the applicable codes and comply with the test and inspection requirements of these codes. These test 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 code requirements are performed. The tests and inspection performed on the reactor vessel are summarized in UFSAR Sections 5.4.5 and 5.4.6.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel.

The RCP seized rotor event is discussed in UFSAR Section 15.3.4. The RCP shaft break event is not part of the St. Lucie Unit 1 licensing basis.

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.

2.8.5.3.2.2 Technical Evaluation

2.8.5.3.2.2.1 Introduction

The RCP rotor seizure (also known as locked rotor) event bounds the consequences of a shaft break event, and is postulated as the instantaneous seizure of a (single) RCP rotor. Flow through the faulted RCS loop rapidly decreases, causing a reactor trip on low RCS flow signal and a turbine trip on the reactor trip. Furthermore, a loss of offsite power is assumed to occur at the time of reactor trip, which causes the remaining RCPs to begin coasting down.

Following the reactor trip, heat stored in the fuel rods continues to be transferred to the reactor coolant. The combination of the relatively high fuel rod surface heat fluxes, decreasing core flow, and increasing core coolant temperatures challenges the departure from nucleate boiling ratio (DNBR) safety limit and may result in fuel failure.

At the same time, the steam generator (SG) primary-to-secondary heat transfer rate decreases, because (1) the decreasing primary coolant flow degrades the SG tube primary side heat transfer coefficients and (2) the turbine trip causes the secondary-side temperature to increase. Decreasing rate of heat removal in the SGs, combined with decreasing flow of coolant removing heat from the reactor core, cause the reactor coolant to heat up. The resultant reactor coolant expansion causes fluid to surge into the pressurizer and an increase in RCS pressure, with the potential for lifting safety valves. The event may challenge the RCS overpressure criterion.

Since the systems designed to mitigate this event (namely, the reactor protection system (RPS)) are redundant, there is no single active failure that will adversely affect the consequences of the event.

2.8.5.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – Hot full power (HFP) initial conditions, maximum Technical Specification (TS) core inlet temperature and minimum TS RCS flow rate were assumed in order to minimize the initial margin to departure from nucleate boiling (DNB).
- Reactivity Feedback – Since this event involves an increase in the core coolant temperature, the event was assumed to occur at beginning of cycle (BOC) with a maximum TS/core operating limits report (COLR) moderator temperature coefficient (MTC) at full power. However, this event occurs quickly and is generally not sensitive to neutronic parameters. A minimum HFP scram worth was used to conservatively maintain relatively high core power during the decrease in core flow.

- Reactor Protection System Trips and Delays – The event is primarily protected by the low flow RPS trip. The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil delay time.
- Loss of Offsite Power – Loss of offsite power at the time of turbine trip (resulting from reactor trip) was assumed. The remaining three RCPs were assumed to begin to coast down with the loss of offsite power which conservatively reduced the flow for the calculation of DNB. The coastdown characteristics of the RCPs were conservatively benchmarked to plant data.
- Gap Conductance – Gap conductance was set to a conservative BOC value to delay the transfer of heat from the fuel rod to the coolant allowing the primary system flow to decay further, thus leading to a conservative prediction of DNBR.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The principally challenged acceptance criterion for this event is with respect to radiological consequences. The analysis documented in this section does not address radiological consequences directly; rather, the extent of fuel failure is determined which is an input to the radiological analyses. The radiological dose analyses are documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

The RCP rotor seizure event does not represent a significant challenge to fuel centerline melting because there is no large power increase and no significant adverse power redistribution within the core. Also, the increase in RCS pressure for this event is much less severe than the result of loss of external load event (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum).

2.8.5.3.2.2.3 Description of Analyses and Evaluation

The current analyses for this event were performed with the non-LOCA methodologies based on the PTSPWR2 code (Reference 1). For the EPU, detailed analyses were performed with approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of minimum departure from nucleate boiling ratio (MDNBR). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 3), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 5). A statistical DNBR analysis was performed using the Reference 4 methodology.

A single case was analyzed for DNBR at BOC HFP initial conditions, maximum TS core inlet temperature and minimum TS RCS flow rate. Inlet flow asymmetries were modeled using 5% flow penalty on the hot channel and four face adjacent channels. This modeling parameter is applicable and conservative because modeling assumptions for flow mixing in the lower plenum do not have a first order effect on MDNBR. The analytical method applies an exit skewed axial power shape, and the inlet flow asymmetries quickly become more uniform in a PWR open lattice core. The factors affecting scram time were biased using conservative trip signal delay and holding coil times to produce the most significant challenge to the DNB limit.

2.8.5.3.2.2.4 Evaluation of 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

The sequence of events is given in LR Table 2.8.5.3.2-1. Results are given in LR Table 2.8.5.3.2-2. The MDNBR was statistically calculated to be greater than the 95/95 limit for the HTP DNB correlation. Thus, no fuel failure due to DNB is predicted to occur.

Plots of key system parameters are shown in LR Figures 2.8.5.3.2-1 through 2.8.5.3.2-6. LR Figure 2.8.5.3.2-1 shows the reactor power as a function of time and LR Figure 2.8.5.3.2-2 shows the core power based on rod surface heat flux. LR Figure 2.8.5.3.2-3 through 2.8.5.3.2-6 show pressurizer pressure, RCS loop temperatures, total RCS flow rate, and reactivity feedback, respectively.

Since no fuel failures are predicted, the fuel failure limits in the radiological dose analyses documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST) are met.

2.8.5.3.2.3 Conclusion

FPL has reviewed the analyses of the RCP rotor seizure event, which bounds the RCP shaft break 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 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 RCP rotor seizure and shaft break events.

2.8.5.3.2.4 References

1. ANF-84-73(P)(A), Revision 5, Appendix B, & Supplements 1 and 2, Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events, Advanced Nuclear Fuels Corporation, October 1990.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. EMF-1961(P)(A), Revision 0, Statistical/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

5. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.3.2-1
Reactor Coolant Pump Rotor Seizure
Sequence of Events

Event	Time (sec)
Seizure of Pump 1A	0.0
Low RCS flow trip setpoint reached	0.168
Reactor scram (including trip response delay)	1.193
CEA insertion begins	1.693
MDNBR occurs	3.1

Table 2.8.5.3.2-2
Reactor Coolant Pump Rotor Seizure
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis	Limit
MDNBR (% fuel failure)	Fuel failure 2.5%	1.211 (0%)	1.164

Figure 2.8.5.3.2-1
Reactor Coolant Pump Rotor Seizure
Reactor Power

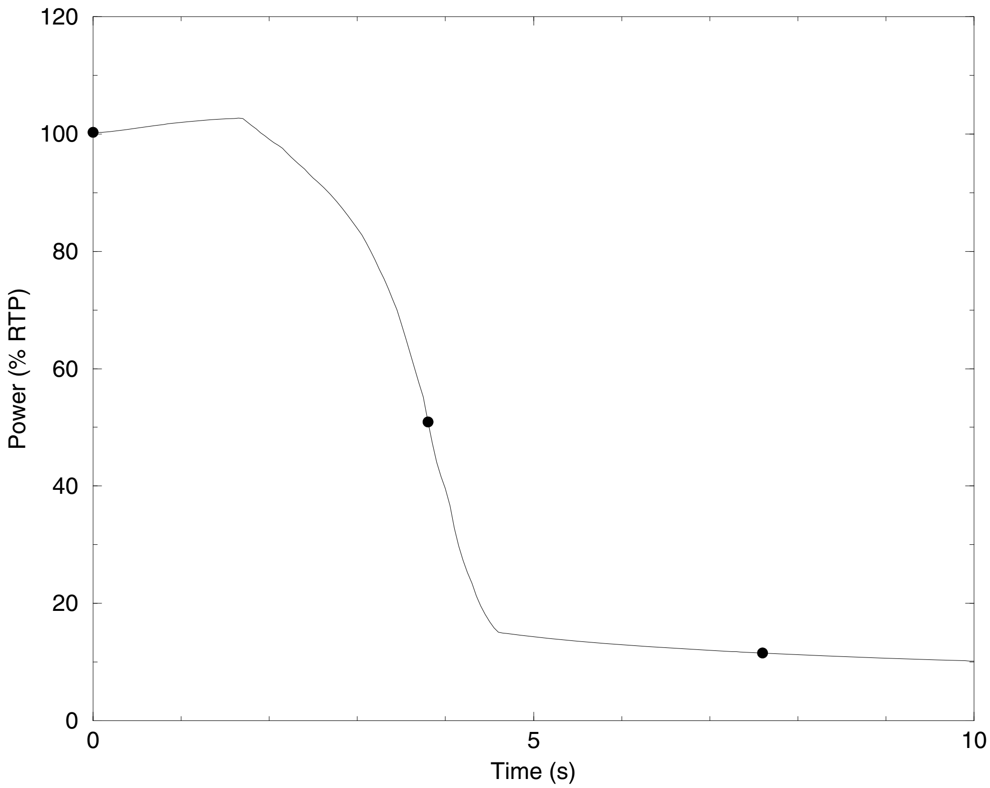


Figure 2.8.5.3.2-2
Reactor Coolant Pump Rotor Seizure
Total Core Heat Flux Power

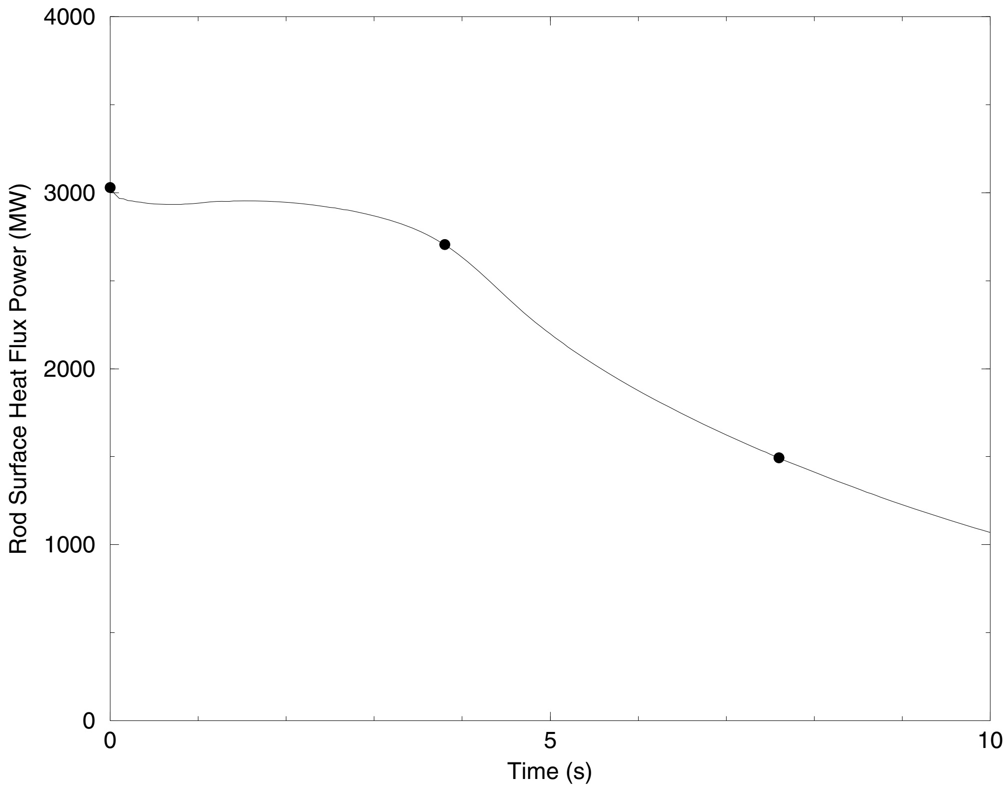


Figure 2.8.5.3.2-3
Reactor Coolant Pump Rotor Seizure
Pressurizer Pressure

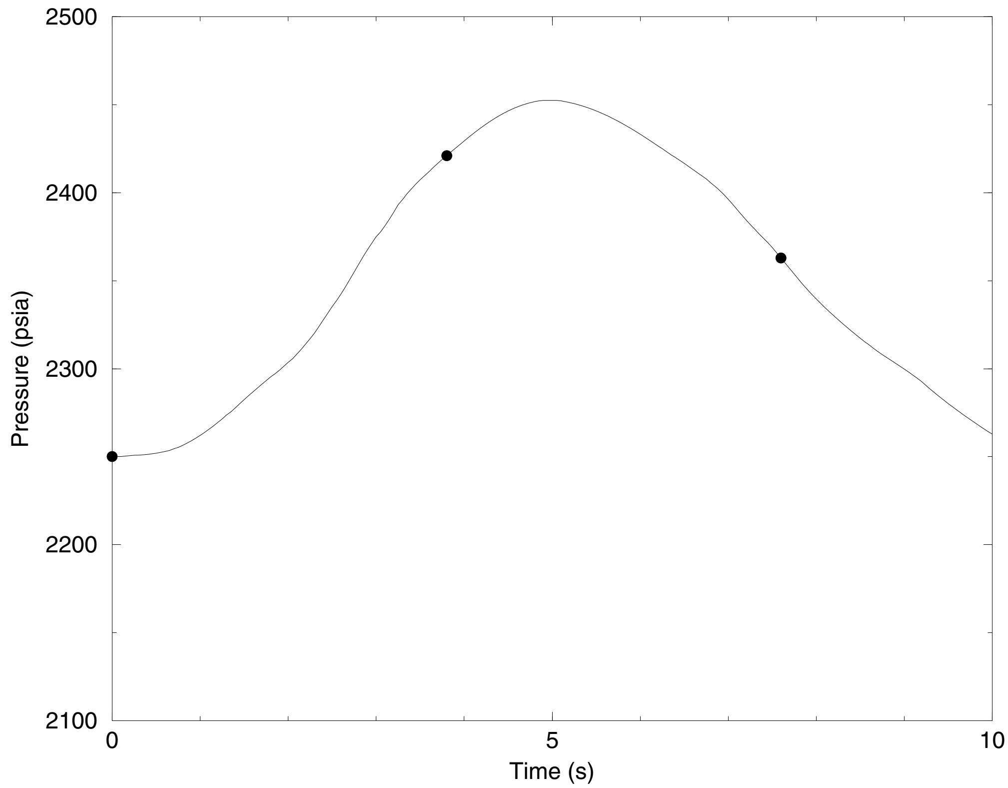


Figure 2.8.5.3.2-4
Reactor Coolant Pump Rotor Seizure
RCS Loop Temperatures

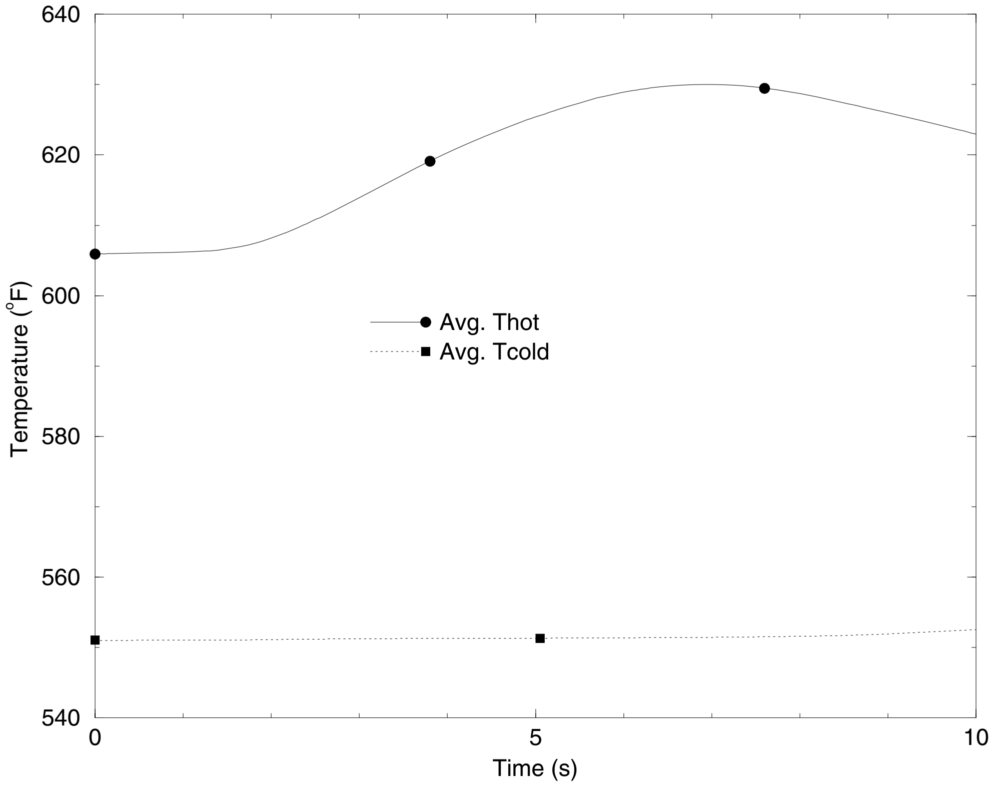


Figure 2.8.5.3.2-5
Reactor Coolant Pump Rotor Seizure
RCS Total Loop Flow Rate

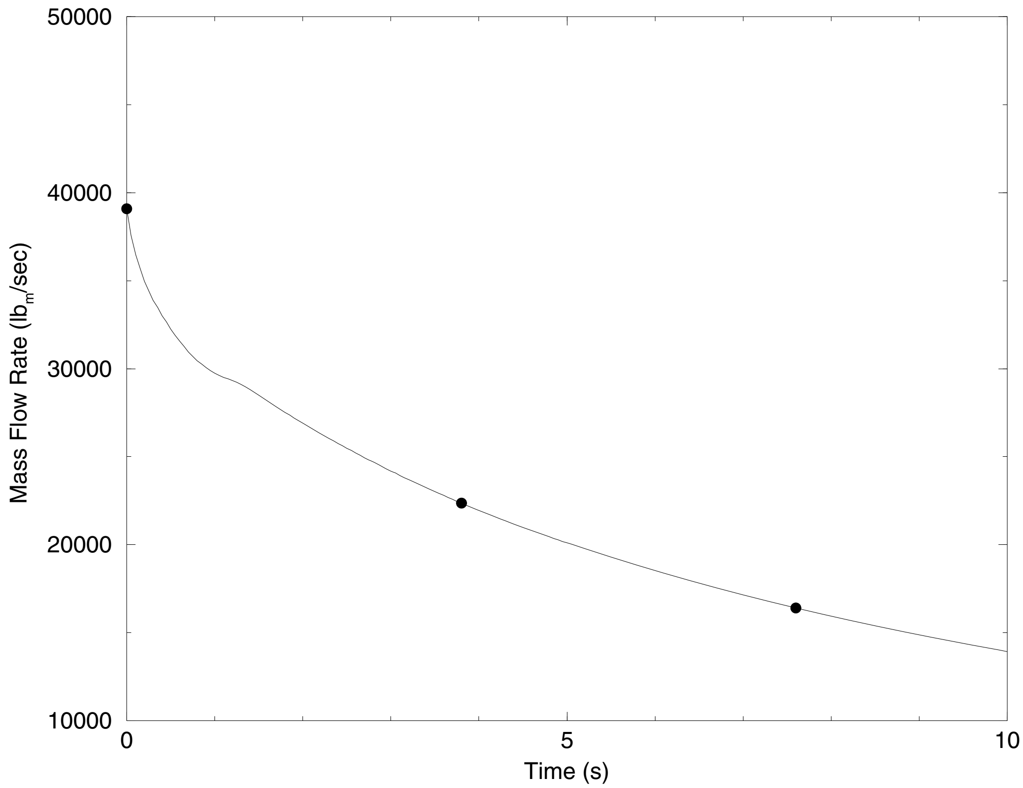
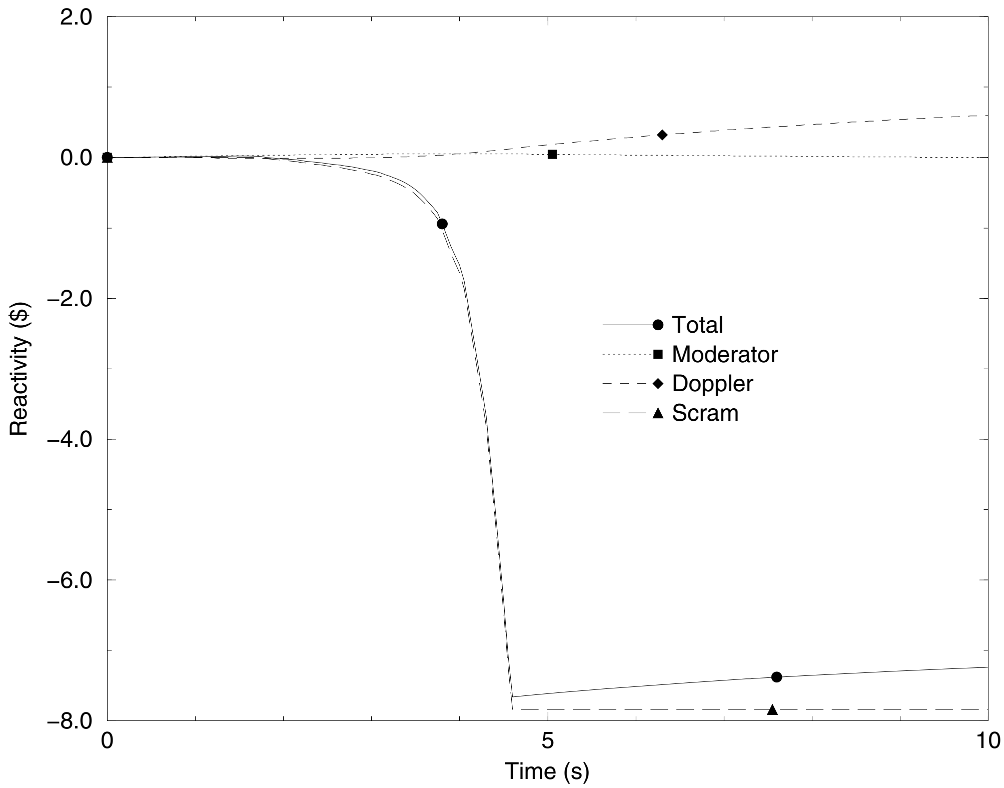


Figure 2.8.5.3.2-6
Reactor Coolant Pump Rotor Seizure
Reactivity Feedback



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 element assembly (CEA) 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.

FPL's 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 Plan (SRP) Section 15.4.1 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 protective system 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 acceptable fuel design limits to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features (ESF) actuation system 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.

- 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 Sections 15.2.1 and 15.2.2. The RPS will prevent SAFDLs from being exceeded for any anticipated transients.

Discussion of the uncontrolled CEA withdrawal from a subcritical or low power startup condition event is provided in UFSAR Section 15.2.1.

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.

2.8.5.4.1.2 Technical Evaluation

2.8.5.4.1.2.1 Introduction

This event is initiated by a continuous CEA withdrawal that could result from: (1) operator error and (2) a malfunction in the reactor regulating system or control element drive system. The event is initiated from a Mode 2 startup (critical) condition at zero power. The event is characterized by a large and rapid positive reactivity insertion that can challenge the departure from nucleate boiling (DNB) and fuel centerline melt (FCM) SAFDLs and RCS pressure. The power excursion prior to reactor trip is mitigated by Doppler reactivity feedback.

2.8.5.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event were set consistent with the approved Reference 1 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – Hot zero power (HZP) initial conditions, maximum HZP core inlet temperature and minimum TS RCS flow rate for four reactor coolant pump (RCP) operation were assumed in order to maximize the challenge to DNB and FCM SAFDLs.

  Additional cases from HZP were run for evaluation of peak RCS pressure. Maximum HZP core inlet temperature and minimum TS RCS flow rate were used for these calculations.

- Reactivity Feedback – Beginning of cycle (BOC) and end of cycle (EOC) parameters were evaluated. TS/core operating limits report (COLR) moderator temperature coefficients (MTC) at HZP were modeled. Scram worth was conservatively set to the minimum TS/COLR shutdown margin.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion into the core is delayed to account for the CEA holding coil delay time. For conservatism, the high rate-of-change trip was not credited in the analysis of this event initiated from HZP. The existence of this trip, however, makes initiating this event from subcritical modes of operation inconsequential.

- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters and power operated relief valves (PORVs)) parameters and equipment states were conservatively treated for both the SAFDL analysis and the RCS overpressure analysis. For the SAFDL cases, the pressurizer pressure control parameters and equipment states were selected to reduce the primary system pressure which provided a conservative calculation of the minimum departure from nucleate boiling ratio (MDNBR) during the transient. For the RCS overpressure cases, the pressurizer pressure control parameters and equipment states were selected to maximize the primary system pressure which provided a conservative calculation of the peak RCS pressure during the transient.

- CEA Withdrawal Characteristics – Bounding differential worth was assumed together with a maximum CEA withdrawal speed. The CEA was conservatively assumed to continuously withdraw beyond the time of reactor trip.
- Gap Conductance – Gap conductance was set to a conservative value, consistent with the time-in-cycle for the reactivity coefficients, to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The principally challenged acceptance criteria for this event are:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

  This criterion is met by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the 95/95 DNB correlation limit. Additionally, FCM is demonstrated to be precluded in the most adverse location in the core.
- The pressure in the reactor coolant system should be less than 110% of the design value.

  This criterion is met by assuring that the peak RCS pressure is less than the acceptance criterion of 2750 psia, i.e., 110% of the design pressure.

2.8.5.4.1.2.3 Description of Analyses and Evaluations

The higher rated power of the extended power uprate (EPU) has negligible impact on the challenge to minimum departure from nucleate boiling ratio (MDNBR). Additionally, this event does not significantly challenge MDNBR. The higher rated power produces a small reduction in margin to the FCM limit.

Although the pre-EPU analysis of this event is described in UFSAR Section 15.2.1.1, this event is subsequently dispositioned as being bounded by the CEA withdrawal at power event. For the EPU, detailed analyses were performed with approved methodology given in Reference 1. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 2), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 3).

A hot-spot model in S-RELAP5 was used to calculate the fuel centerline temperature during the transient.

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

Analysis to Verify Specified Acceptable Fuel Design Limits

The limiting SAFDL case occurred at BOC HZP initial conditions, maximum HZP core inlet temperature, and minimum TS RCS flow rate. Due to more positive reactivity feedback, the power excursion is maximized at BOC relative to EOC. Maximizing the power excursion presents the most significant challenge to the SAFDLs.

The sequence of events is given in LR Table 2.8.5.4.1-1.

Plots of key system parameters are shown in LR Figures 2.8.5.4.1-1 through 2.8.5.4.1-8. LR Figure 2.8.5.4.1-1 shows reactor power as a function of time. LR Figure 2.8.5.4.1-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.4.1-3 through 2.8.5.4.1-8 show the pressurizer pressure, the RCS loop temperatures, the total RCS flow rate, the steam generator pressures, the reactivity feedback, and the peak fuel centerline temperature, respectively.

Results are given in LR Table 2.8.5.4.1-2. The MDNBR for the limiting case (BOC, 10.0 pcm/sec) was calculated to be above the 95/95 limit for the HTP CHF correlation. The peak fuel centerline temperature was calculated to be less than the fuel centerline melt limit.

Analysis to Verify RCS Overpressure Limit

Calculations were performed to evaluate the peak RCS pressure for this event. The limiting case for evaluation of the challenge to the RCS pressure limit was at BOC HZP initial conditions. The sequence of events is given in LR Table 2.8.5.4.1-1. Results are given in LR Table 2.8.5.4.1-2. LR Figure 2.8.5.4.1-9 shows the peak RCS pressure (2568 psia) for the limiting case (BOC, 0.671 pcm/sec) which is less than the acceptance criterion of 2750 psia. The peak RCS pressure for this event is bounded by the loss of external load (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum).

2.8.5.4.1.2.6 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 specified acceptable fuel design limits and RCS pressure limits 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 from a subcritical or low power startup condition.

2.8.5.4.1.2.7 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.4.1-1
Uncontrolled CEA Withdrawal from Subcritical
Sequence of Events

	Event	Time (sec)
SAFDL	Bank withdrawal begins at BOC (10.0 pcm/sec)	0.0
	Core power reached VHPT setpoint	55.2
	Reactor scram on VHPT (including trip response delay)	56.3
	CEA insertion begins	56.8
	Maximum core power	56.8
	Maximum heat flux	58.5
	MDNBR	58.5
	Maximum fuel centerline temperature	59.0
RCS Pressure	Bank withdrawal begins at BOC (0.671 pcm/sec)	0.0
	Core power reached VHPT setpoint	429.9
	Pressurizer pressure reaches HPPT	430.1
	Reactor scram on VHPT or HPPT (including trip response delay)	431.0
	CEA insertion begins	431.5
	Maximum core power	431.5
	Peak RCS pressure	434.9

Table 2.8.5.4.1-2
Uncontrolled CEA Withdrawal from Subcritical
Results

Criterion	EPU Analysis	Limit
MDNBR	6.087	1.164
Fuel centerline temperature	2036°F	4908°F
Peak RCS Pressure	2568 psia	2750 psia

Figure 2.8.5.4.1-1
Uncontrolled CEA Withdrawal from Subcritical
Reactor Power (BOC SAFDL)

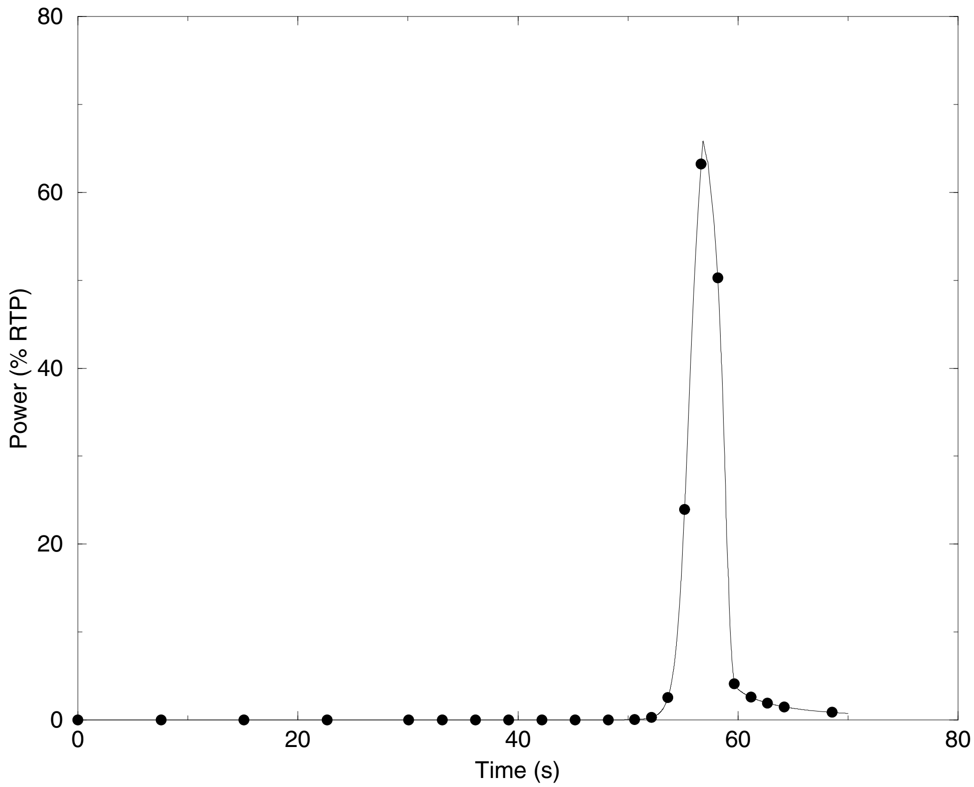


Figure 2.8.5.4.1-2
Uncontrolled CEA Withdrawal from Subcritical
Total Core Heat Flux Power (BOC SAFDL)

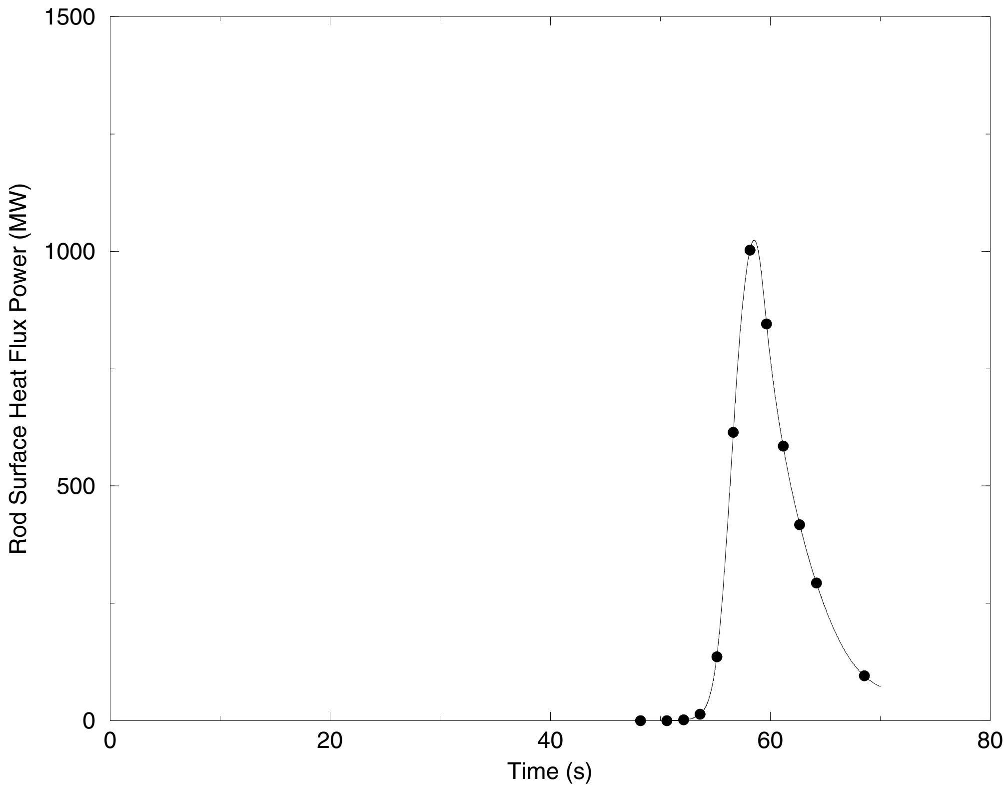


Figure 2.8.5.4.1-3
Uncontrolled CEA Withdrawal from Subcritical
Pressurizer Pressure (BOC SAFDL)

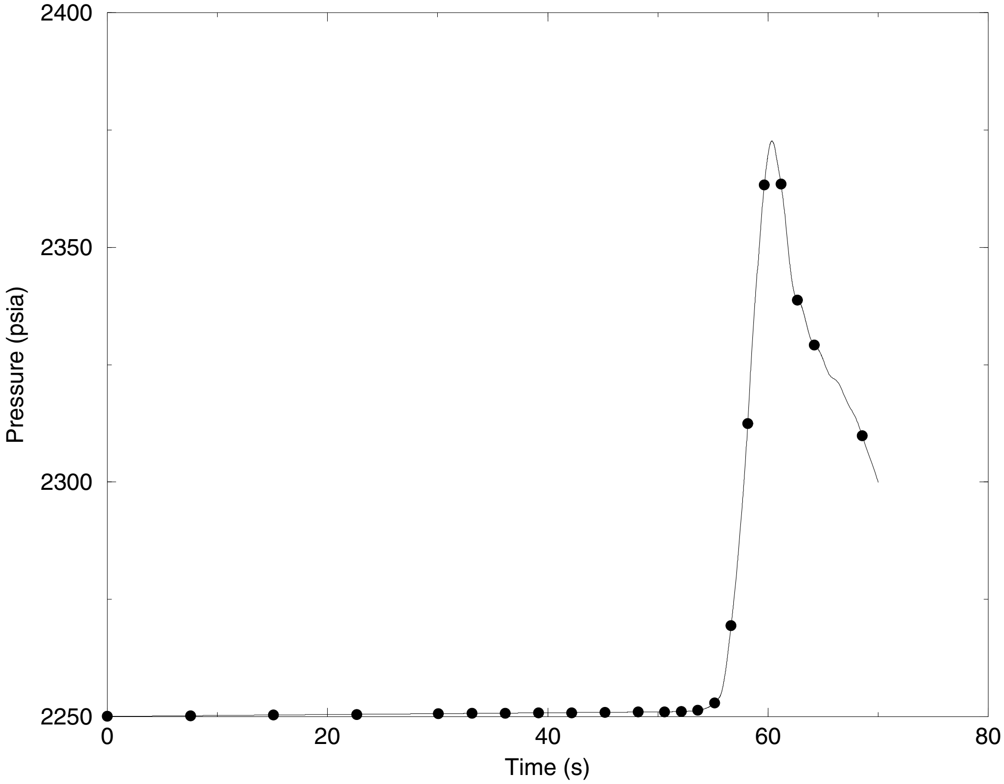


Figure 2.8.5.4.1-4
Uncontrolled CEA Withdrawal from Subcritical
RCS Loop Temperature (BOC SAFDL)

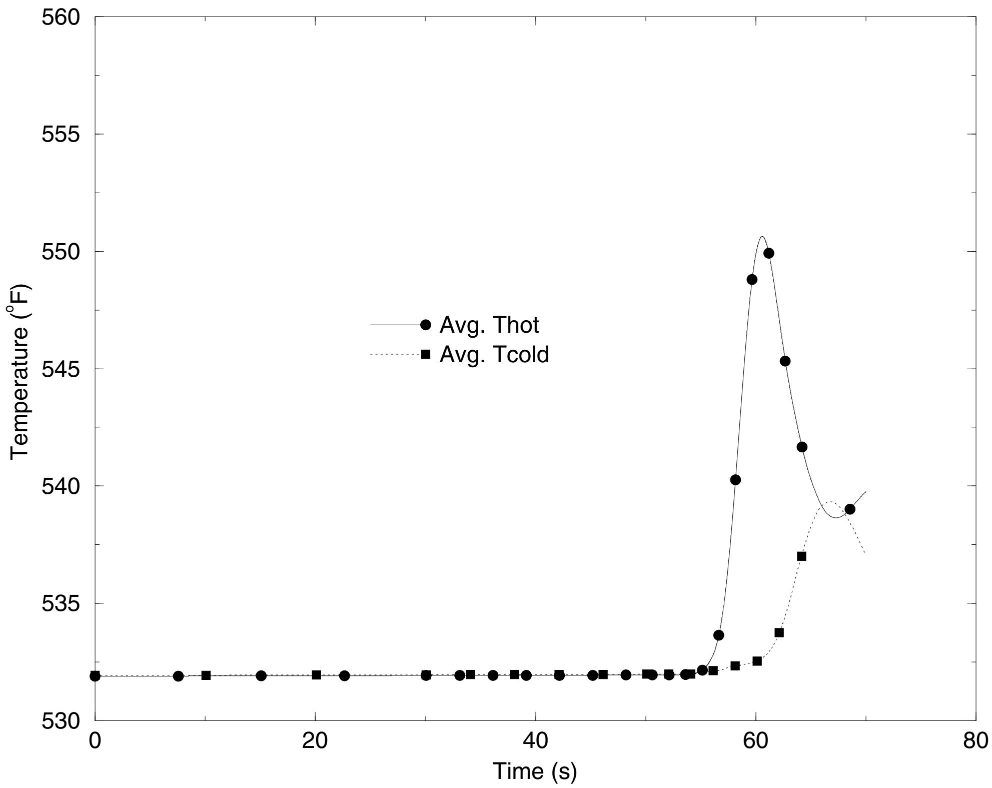


Figure 2.8.5.4.1-5
Uncontrolled CEA Withdrawal from Subcritical
RCS Total Loop Flow Rate (BOC SAFDL)

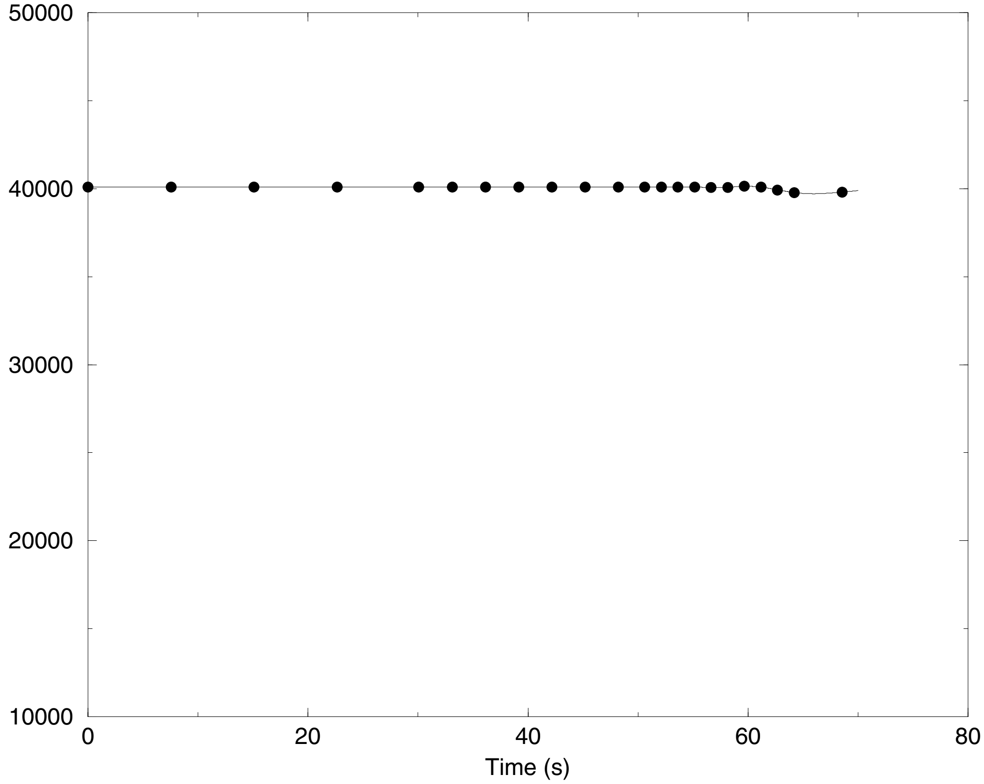


Figure 2.8.5.4.1-6
Uncontrolled CEA Withdrawal from Subcritical
Steam Generator Pressures (BOC SAFDL)

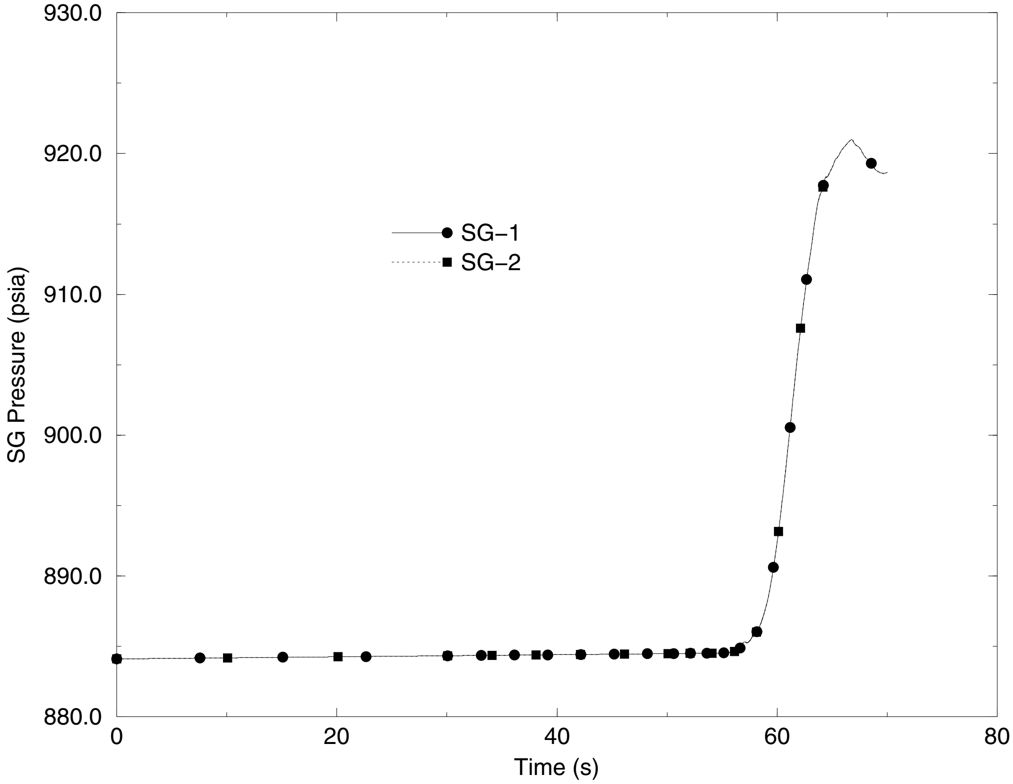


Figure 2.8.5.4.1-7
Uncontrolled CEA Withdrawal from Subcritical
Reactivity Feedback (BOC SAFDL)

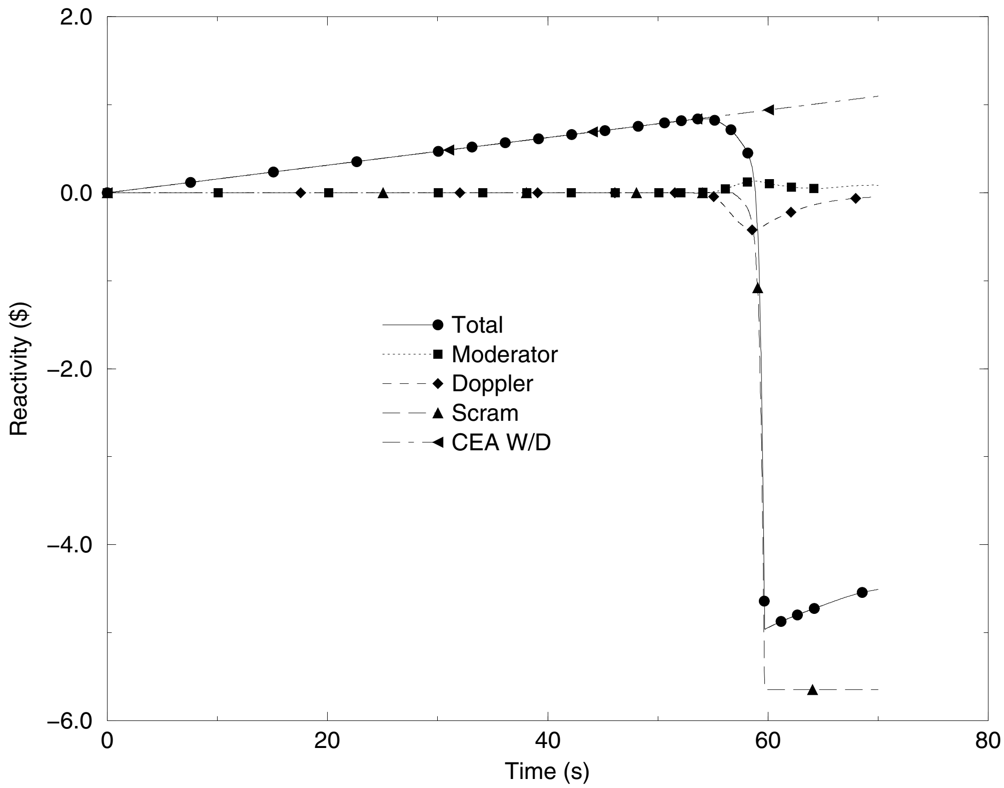


Figure 2.8.5.4.1-8
Uncontrolled CEA Withdrawal from Subcritical
Peak Fuel Centerline Temperature (BOC SAFDL)

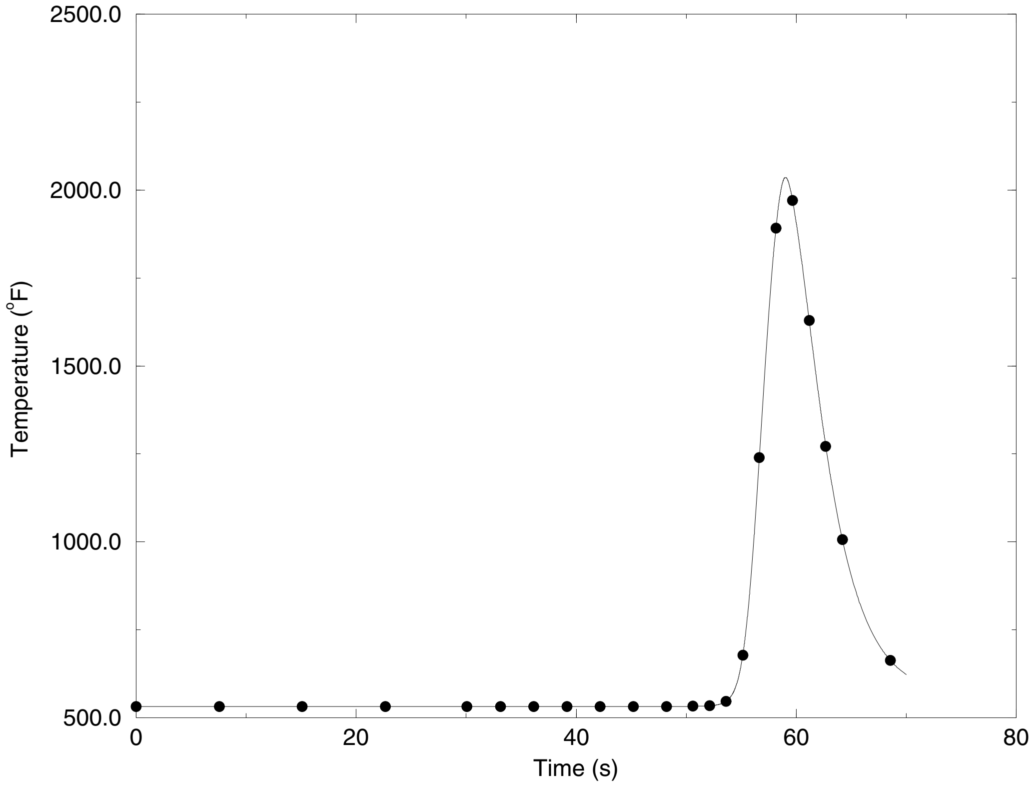
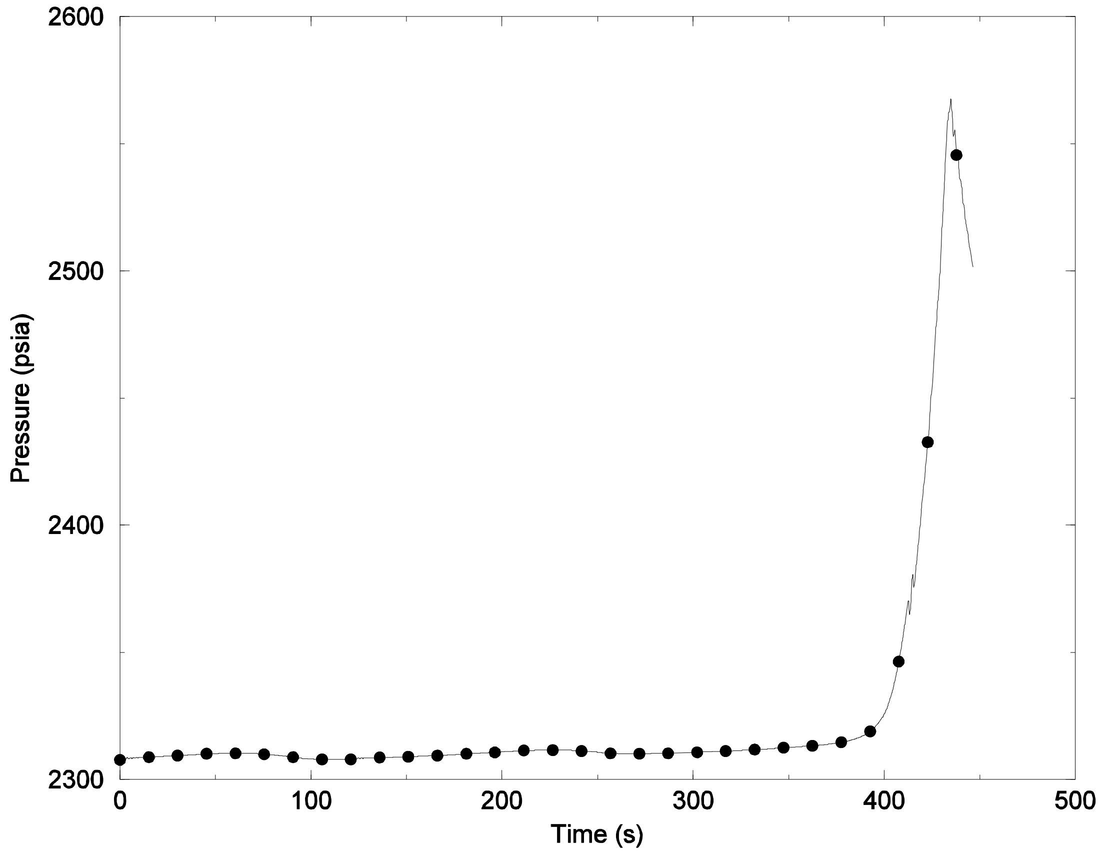


Figure 2.8.5.4.1-9
Uncontrolled CEA Withdrawal from Subcritical
Peak RCS Pressure (BOC RCS Pressure)



2.8.5.4.2 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power can 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 & 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:

- 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 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 Plan (SRP) Section 15.4.2 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the uncontrolled control rod assembly withdrawal at power 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. (Refer to UFSAR Section 7.2 and Chapter 15.)

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 protective system 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.

The engineered safety features actuation system 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 and 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 Sections 15.2.1 and 15.2.2. The reactor protection system (RPS) will prevent SAFDLs from being exceeded for any anticipated transients.

Discussion of the uncontrolled CEA withdrawal at power event is provided in UFSAR Section 15.2.1.

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.

2.8.5.4.2.2 Technical Evaluation

2.8.5.4.2.2.1 Introduction

An inadvertent CEA bank withdrawal at power could be caused by two potential initiators: (1) operator error, or (2) a malfunction of either the CEAs or of the CEDMs which results in an uncontrolled, continuous CEA bank withdrawal. The positive reactivity addition from the CEA withdrawal results in a power transient. Due to relatively constant heat extraction from the steam generators during the event, the increase in reactor power produces an increase in reactor coolant temperatures and core heat flux, thereby decreasing the margin to the departure from nucleate boiling (DNB) and fuel centerline melt (FCM) SAFDLs, and the reactor coolant system (RCS) overpressure limit.

While a continuous CEA withdrawal is considered unlikely, the reactor protective system is designed to terminate any such transient before fuel thermal design and RCS overpressure limits are reached. Protection against violation of the SAFDLs and RCS overpressure limits is provided primarily by the variable high power (VHP), thermal margin/low pressure (TM/LP), local power density and high pressurizer pressure (HPP) trips.

2.8.5.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Key input parameters were biased conservatively relative to the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – For evaluation of the SAFDLs, part-power levels (25%, 50%, 75% and 97.39%) and hot full power (HFP) were evaluated with a maximum core inlet temperature and TS minimum RCS flow in order to ensure that the limiting initial conditions relative to the challenge to the SAFDLs were identified.

  For evaluation of peak RCS pressure, part-power levels (25%, 50% and 75%) and full power were analyzed. For additional conservatism the initial pressurizer pressure, cold leg temperature and RCS flow rate were biased for the limiting case to account for operating ranges and measurement uncertainties.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. Both beginning of cycle (BOC) and end of cycle (EOC) kinetics were analyzed to assess the impact of moderator and Doppler feedback. The moderator temperature coefficients (MTCs) were assumed to be a value that is bounding of the most positive TS value for the BOC cases and a value equal to the most negative TS value for the EOC cases. Doppler reactivity was biased to bound a range of feedback from BOC to EOC.

LR Section 2.8.5.0, Accident and Transient Analyses provides the coefficients supported by the analyses. Scram worth was conservatively set to a minimum value appropriate for the initial power level being analyzed.

The neutronic parameters were validated to be representative of EPU core designs expected to be implemented at St. Lucie Unit 1. Key neutronic parameters were evaluated for the third cycle at EPU conditions (Cycle N+2) where the core has essentially reached equilibrium. To ensure that these parameters are representative of the first EPU cycle (Cycle N), the parameters were re-generated and examined for large deviations. No significant deviations in parameters were observed between Cycle N and Cycle N+2.

- Reactor Protection System Trips and Delays – The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, control rod insertion is delayed to account for CEA holding coil delay time.
- Pressurizer Pressure Control – Pressurizer pressure control (i.e., pressurizer sprays, heaters and power operated relief valves (PORVs)) parameters and equipment states were conservatively treated for both the SAFDL analysis and the RCS overpressure analysis. For the SAFDL cases, the pressurizer pressure control parameters and equipment states were selected to reduce the primary system pressure which provided a conservative calculation of the minimum departure from nucleate boiling ratio (MDNBR) during the transient. For the RCS overpressure cases, the pressurizer pressure control parameters and equipment states were selected to maximize the primary system pressure which provided a conservative calculation of the peak RCS pressure during the transient.
- CEA Withdrawal Characteristics – A bounding differential worth was assumed together with a maximum CEA withdrawal speed. As a conservative analytical assumption, withdrawal of the CEA is not terminated at reactor trip.
- Gap Conductance – Gap conductance was set to conservative values consistent with the time-in-cycle for the reactivity coefficients.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The principally challenged acceptance criteria for this event are:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

  This criterion is met by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the 95/95 DNB correlation limit. Additionally, FCM is met by demonstrating that the peak linear heat rate (LHR) is less than the LHR limit corresponding to the FCM temperature.

- The pressure in the reactor coolant system should be less than 110% of the design value.

  This criterion is met by assuring that the peak RCS pressure is less than the acceptance criterion of 2750 psia, i.e., 110% of the design pressure.

2.8.5.4.2.2.3 Description of Analyses and Evaluations

Analyses supporting current plant operation were performed with the non-LOCA methodologies based on the PTSPWR2 code (Reference 1). For the extended power uprate (EPU), detailed analyses were performed with the approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of MDNBR. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 3), which was used to calculate the MDNBR using the HTP critical heat flux (CHF) correlation (Reference 4).

A spectrum of positive insertion rates is possible from very slow to fast, limited only by bank worth and maximum drive speed. Two reactivity feedback matrices of cases are analyzed: One for most-positive reactivity feedback (most-positive MTC and least-negative Doppler coefficient), and the other for most-negative feedback (most-negative MTC and most-negative Doppler coefficient). A range of initial reactor power levels were analyzed for both SAFDL challenge and the RCS pressure challenge.

For both reactivity feedback matrices of cases, the reactivity insertion rates used bound the respective lowest MDNBR point, the highest RCS pressure point and the maximum value for CEA bank withdrawal. The lower bound of the reactivity insertion rate also bounds the reactivity insertion rate corresponding to Mode 1 Boron Dilution.

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

Analysis to Verify Specified Acceptable Fuel Design Limits

Calculations were performed to evaluate the challenge to the SAFDLs for this event. Part-power levels were analyzed as well as full power conditions. Both BOC and EOC kinetics were included in the analyses. The DNB and peak LHR results are given in LR Table 2.8.5.4.2-1. The DNB SAFDL is most challenged at EOC HFP initial conditions. The peak LHR does not significantly challenge the LHR limit for this event. A comparison of results to the previous analysis are given in LR Table 2.8.5.4.2-3.

BOC (HFP, 0.10 pcm/sec)

The sequence of events is given in LR Table 2.8.5.4.2-2. Results are given in LR Table 2.8.5.4.2-1. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation. The peak LHR was calculated to be less than the LHR limit corresponding to fuel centerline melt.

The transient response is shown in LR Figures 2.8.5.4.2-1 through 2.8.5.4.2-7. LR Figure 2.8.5.4.2-1 shows the reactor power as a function of time. LR Figure 2.8.5.4.2-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.4.2-3 though 2.8.5.4.2-7 show the pressurizer pressure, the pressurizer level, the RCS loop temperatures, the total RCS flow rate, and the reactivity feedback, respectively.

EOC (HFP, 9.6 pcm/sec)

The sequence of events is given in LR Table 2.8.5.4.2-2. Results are given in LR Table 2.8.5.4.2-1. The MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation. The peak LHR was calculated to be less than the LHR limit corresponding to fuel centerline melt.

The transient response is shown in LR Figures 2.8.5.4.2-8 through 2.8.5.4.2-14. LR Figure 2.8.5.4.2-8 shows the reactor power as a function of time. LR Figure 2.8.5.4.2-9 shows the core power based on rod surface heat flux. LR Figures 2.8.5.4.2-10 through 2.8.5.4.2-14 show the pressurizer pressure, the pressurizer level, the RCS loop temperatures, the total RCS flow rate, and the reactivity feedback, respectively.

Analysis to Verify RCS Overpressure Limit

Calculations were performed to evaluate the peak RCS pressure for this event. Part-power levels were analyzed as well as full power conditions. Both BOC and EOC kinetics were analyzed for each initial power level. Key input parameters were biased conservatively relative to the approved Reference 2 methodology. The maximum RCS pressures occurred at the intersection of the VHPT and HPPT. The results, given in LR Table 2.8.5.4.2-1, show that peak RCS pressure increases with increasing core power with the overall limiting initial condition being HFP with BOC reactivity feedback.

BOC (HFP, 2.033 pcm/sec)

The sequence of events is given in LR Table 2.8.5.4.2-2. Results are given in LR Table 2.8.5.4.2-1. The peak RCS pressure was calculated to be 2657 psia which is less than the acceptance criterion of 2750 psia. The peak RCS pressure for this event is bounded by the loss of external load (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum).

The transient response is shown in LR Figures 2.8.5.4.2-15 through 2.8.5.4.2-21. LR Figure 2.8.5.4.2-15 shows the reactor power as a function of time. LR Figures 2.8.5.4.2-16 though 2.8.5.4.2-20 show the pressurizer pressure, the pressurizer level, the RCS loop temperatures, the total RCS flow rate, and the reactivity feedback, respectively. LR Figure 2.8.5.4.2-21 shows the peak RCS pressure as a function of time.

2.8.5.4.2.3 Conclusion

FPL has analyzed the uncontrolled control rod assembly withdrawal at power 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 and RCS pressure limit 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. ANF-84-73(P)(A), Revision 5, Appendix B & Supplements 1 and 2, Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events, Advanced Nuclear Fuels Corporation, October 1990.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

Table 2.8.5.4.2-1
Uncontrolled CEA Withdrawal at Power
Analysis Results

Core Power	BOC				EOC			
	MDNBR	Peak LHR (kW/ft)	Peak RCS Pressure (psia)	Peak Pressurizer Level (% of span)[b]	MDNBR	Peak LHR (kW/ft)	Peak RCS Pressure (psia)	Peak Pressurizer Level (% of span)[b]
25% RTP	3.075	12.7	2567	47.4	2.765	12.9	2,57	47.1
50% RTP	2.056	16.5	2582	57.8	1.796	16.7	2576	57.6
75% RTP	1.467	17.9	2610	68.2	1.273	17.8	2604	68.1
97.39% RTP	1.457	17.7	---	---	1.262	17.7	---	---
100% RTP	1.427	17.7	2657[a]	73.8	1.239	17.7	2615	72.6

a. For additional conservatism, beyond that required by the Reference 2 methodology, the initial pressurizer pressure, cold leg temperature and RCS flow rate were biased for the limiting case to account for operating ranges and measurement uncertainties.

b. The cited pressurizer levels were taken from the RCS pressure cases. While the pressurizer levels for the SAFDL cases were higher than those for the RCS pressure cases, the SAFDL cases conservatively did not model the high pressurizer pressure RPS trip for the purpose of predicting conservative DNBRs. As a result the SAFDL cases over-predicted the pressurizer level. The RCS pressure cases included actuation of the high pressurizer pressure RPS trip.

Table 2.8.5.4.2-2
Uncontrolled CEA Withdrawal at Power
Sequence of Events

Case	Event	Time (sec)
Most Positive Feedback SAFDL Case	Bank withdrawal begins	0.0
	PORV Opens	117.3
	Core power reaches VHP trip setpoint	135.0
	Reactor scram on VHPT (including trip response delay[1])	135.8
	MDNBR	136.2
	CEA insertion	136.3
	Maximum core power	136.4
	Maximum heat flux power	136.4
	Pressurizer pressure peaks	137.6
Most Negative Feedback SAFDL Case	Bank withdrawal begins	0.0
	PORV Opens	31.8
	Pressure reaches TM/LP trip setpoint	89.0
	Core power reaches VHP trip setpoint	89.6
	Maximum core power	89.8
	Reactor scram on TM/LP (including trip response delay)	89.9
	Maximum heat flux power	90.0
	MDNBR	90.0
	CEA insertion	90.4
	Pressurizer pressure peaks	91.4
Maximum RCS Pressure Case (BOC, HFP, 2.033 pcm/sec)	Bank withdrawal begins	0.0
	Pressure reaches HPP trip setpoint	28.5
	Reactor scram on HPP trip (including trip response delay)	29.4
	CEA insertion	29.9
	Maximum core power	29.9
	RCS pressure peaks	32.6
	Pressurizer safety valves open	33.0
	Pressurizer safety valves close	33.6

1. Additional VHPT delay was added for the purpose of calculating transient biases for the setpoint calculations

Table 2.8.5.4.2-3
Uncontrolled CEA Withdrawal at Power
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis		Limit
		BOC	EOC	
MDNBR	1.59	1.427	1.239	1.164
Peak LHR (kW/ft)	N/A	17.9	17.8	22.279

Figure 2.8.5.4.2-1
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
Reactor Power

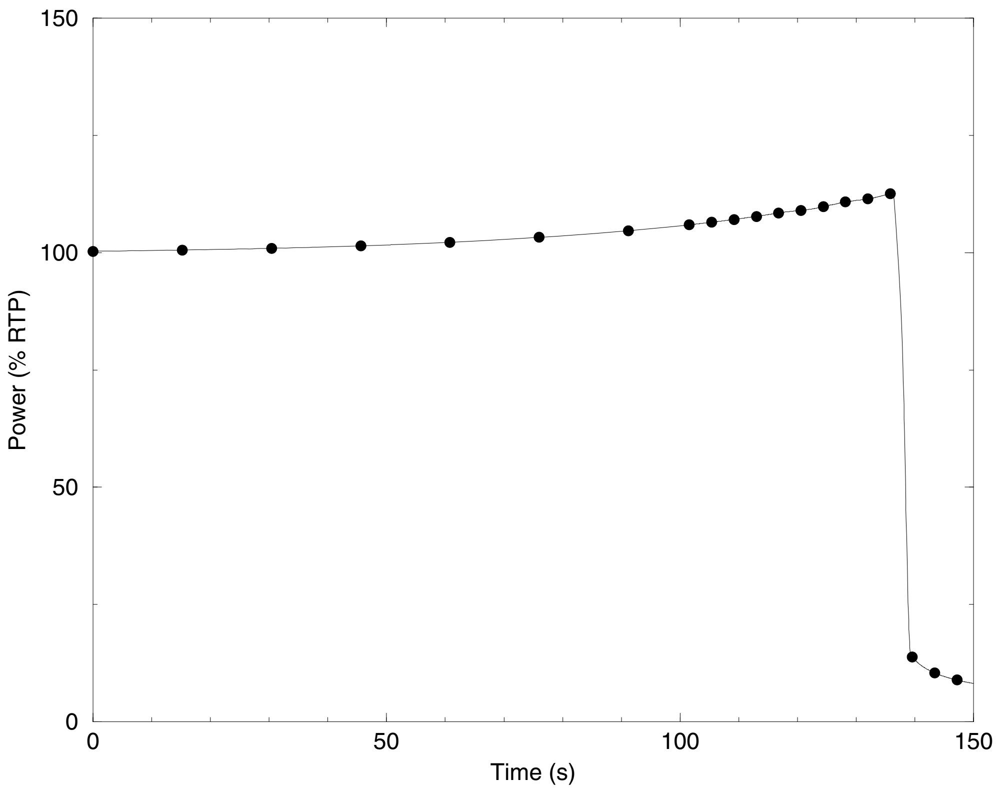


Figure 2.8.5.4.2-2
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
Total Core Heat Flux Power

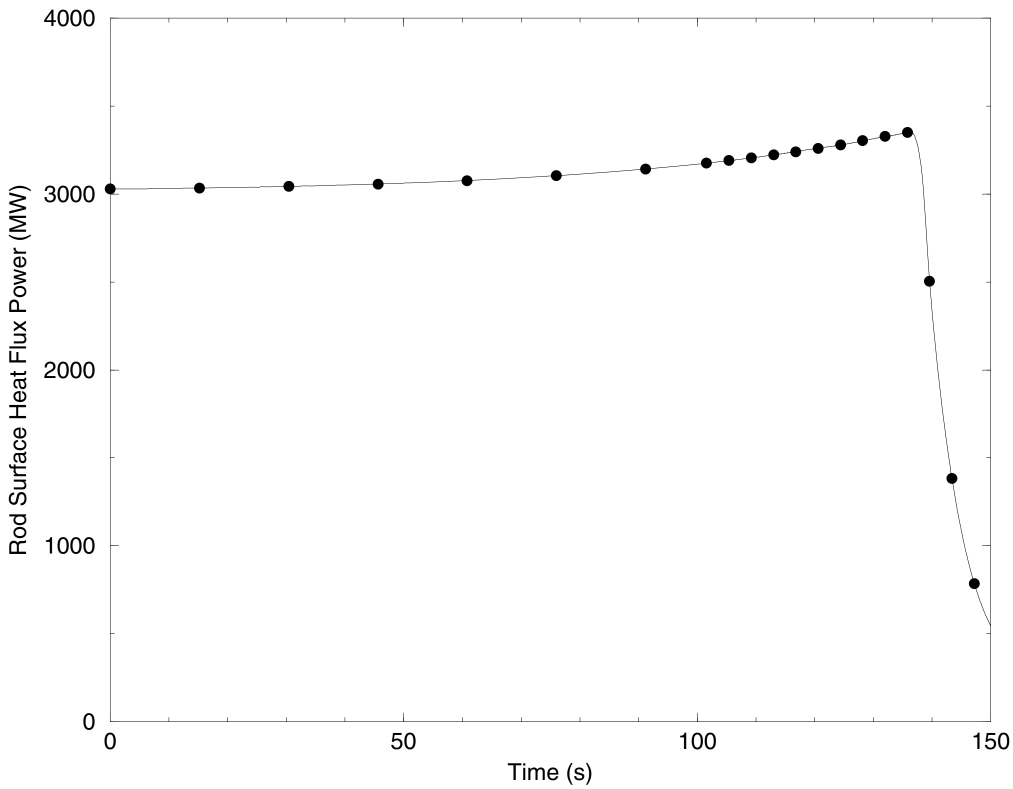


Figure 2.8.5.4.2-3
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
Pressurizer Pressure

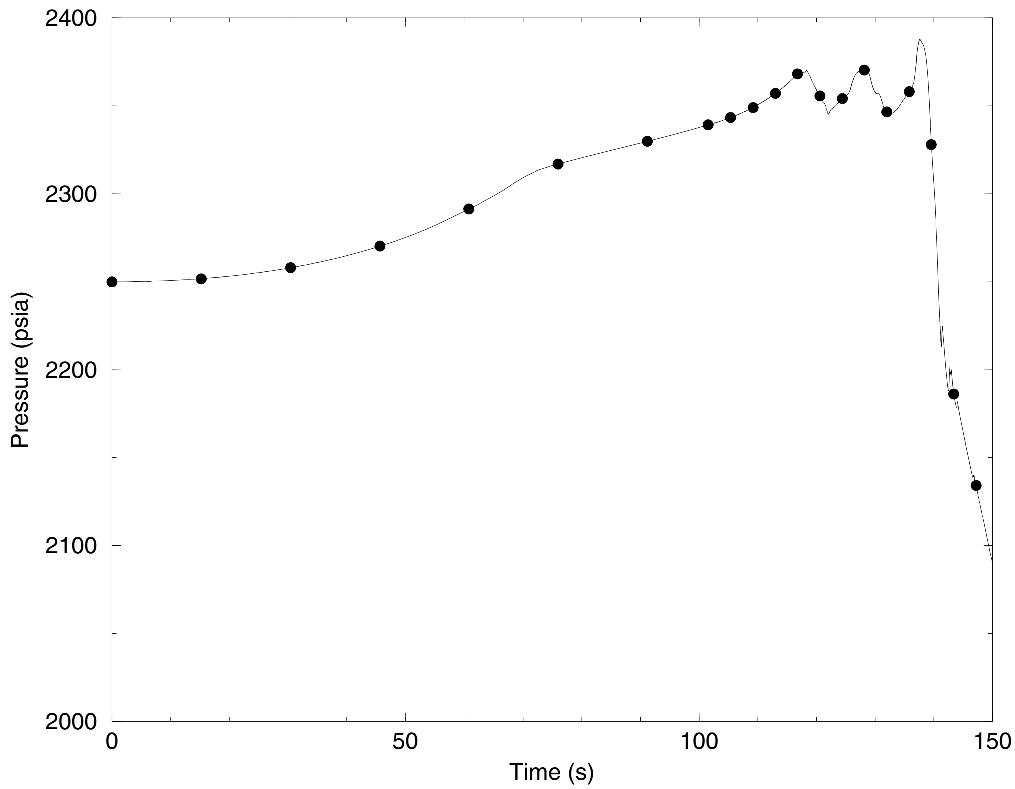


Figure 2.8.5.4.2-4
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
Pressurizer Liquid Level

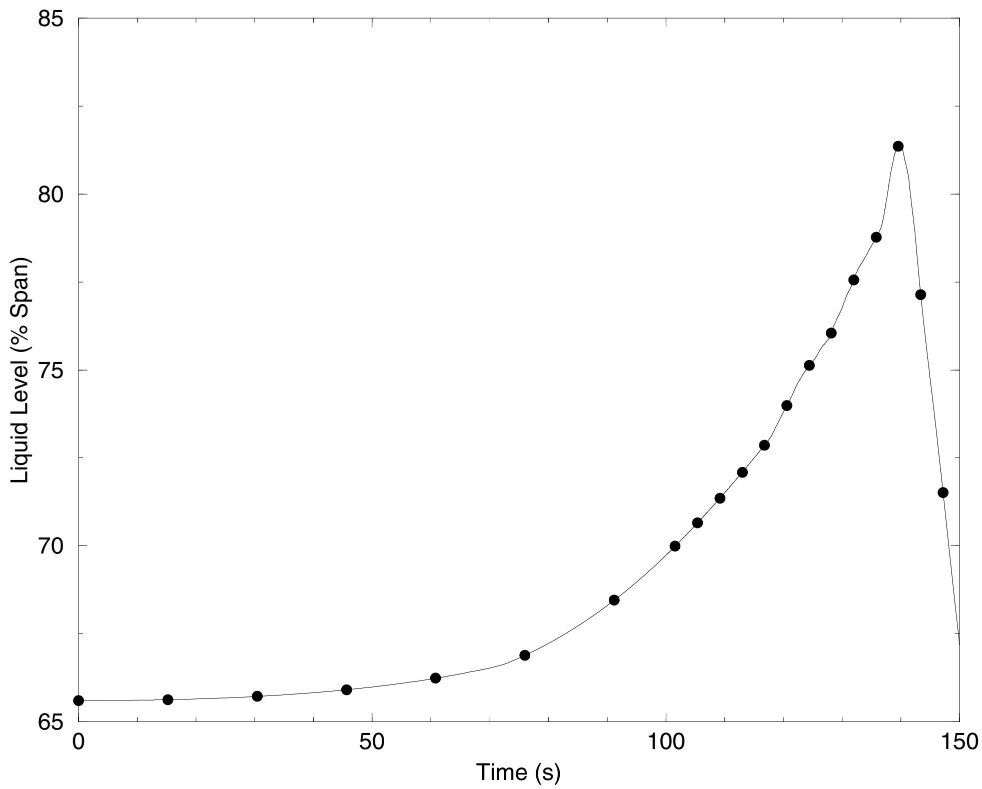


Figure 2.8.5.4.2-5
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
RCS Loop Temperatures

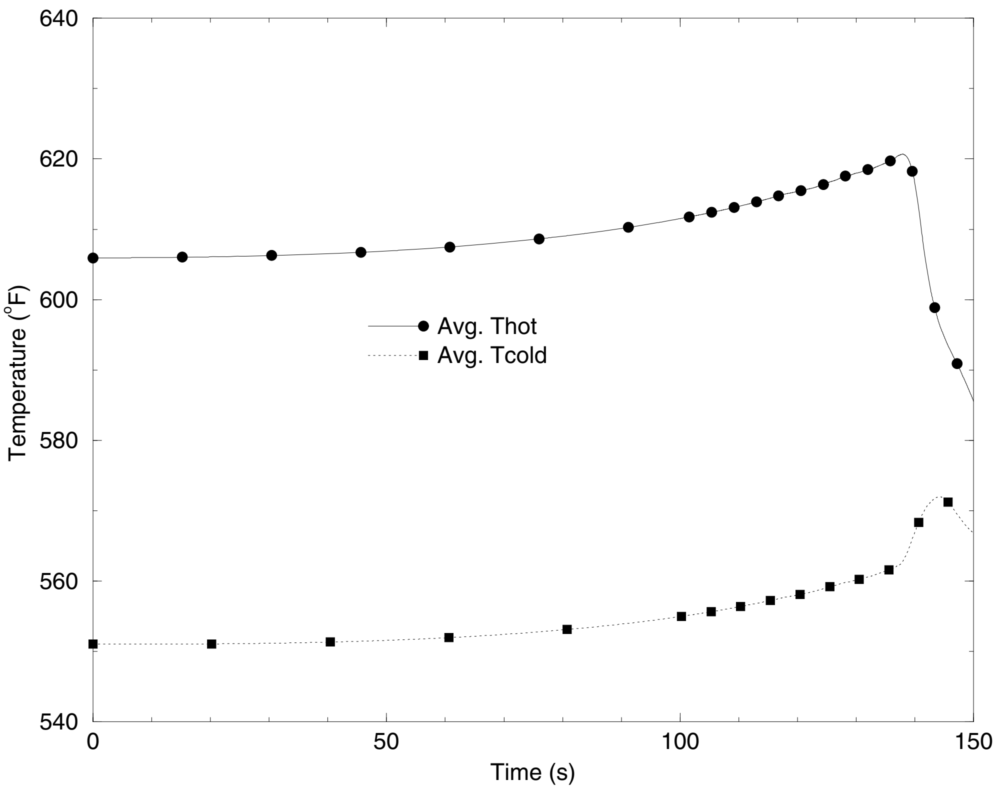


Figure 2.8.5.4.2-6
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
RCS Total Loop Flow Rate

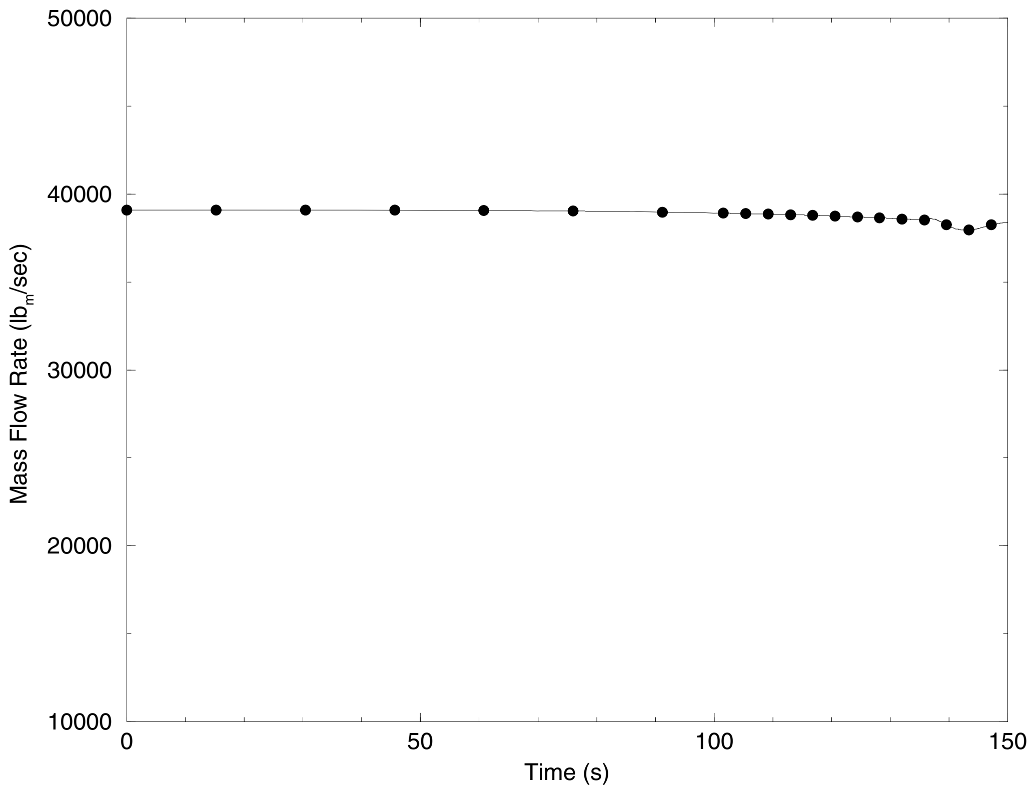


Figure 2.8.5.4.2-7
Uncontrolled CEA Withdrawal at Power (SAFDL Case)
(BOC, 0.1 pcm/sec)
Reactivity Feedback

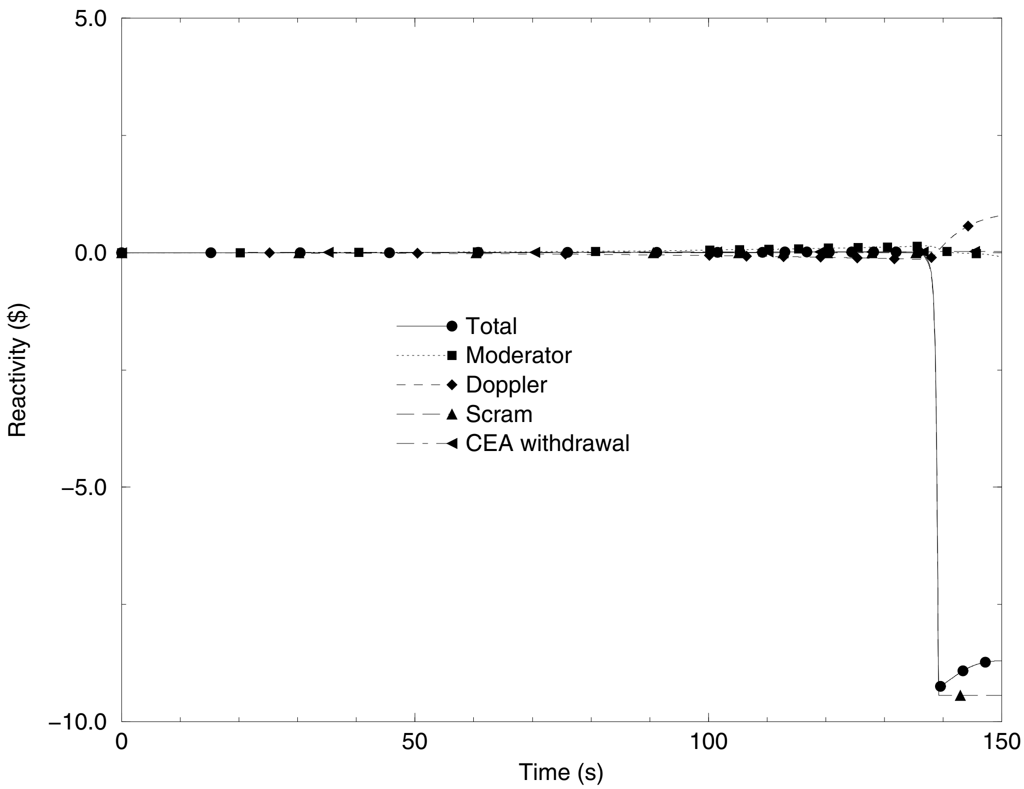


Figure 2.8.5.4.2-8
(SAFDL Case)
(EOC, 9.6 pcm/sec)
Reactor Power

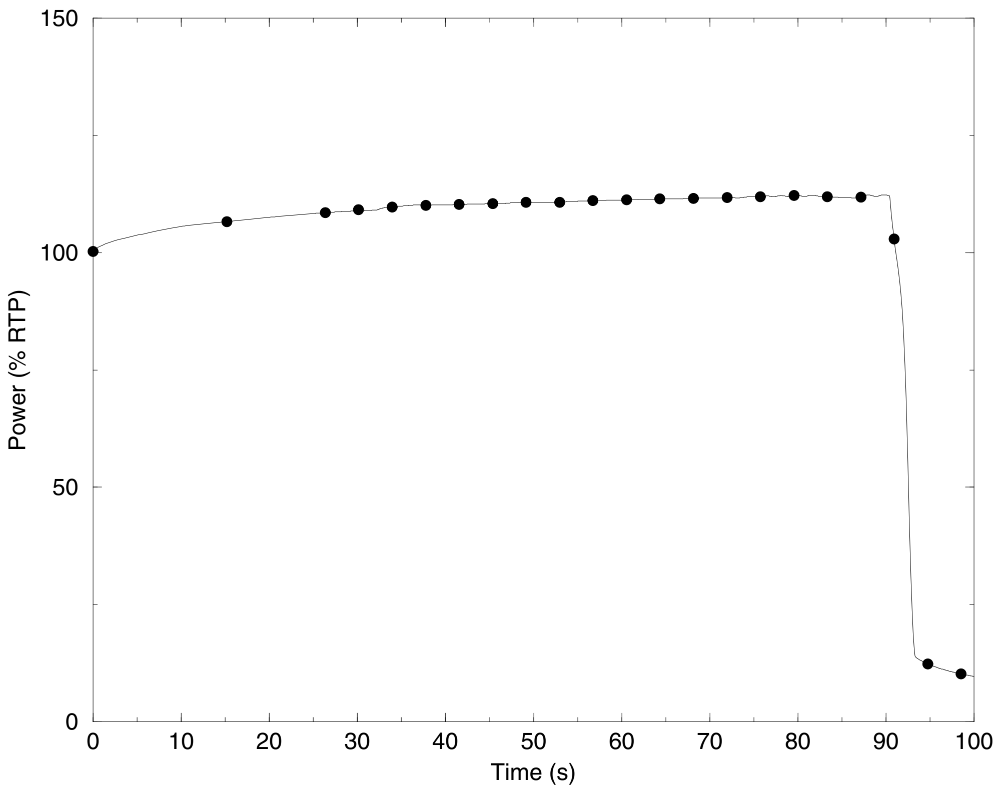


Figure 2.8.5.4.2-9
(SAFDL Case)
(EOC, 9.6 pcm/sec)
Total Core Heat Flux Power

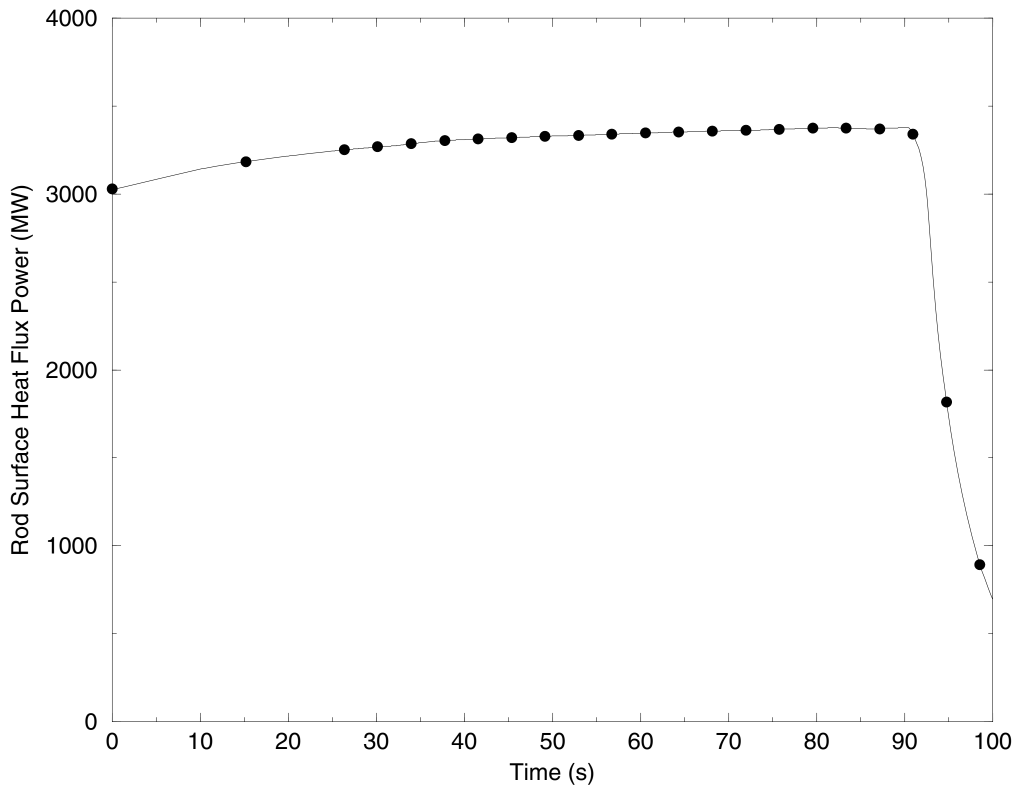


Figure 2.8.5.4.2-10
(SAFDL Case)
(EOC, 9.6 pcm/sec)
Pressurizer Pressure

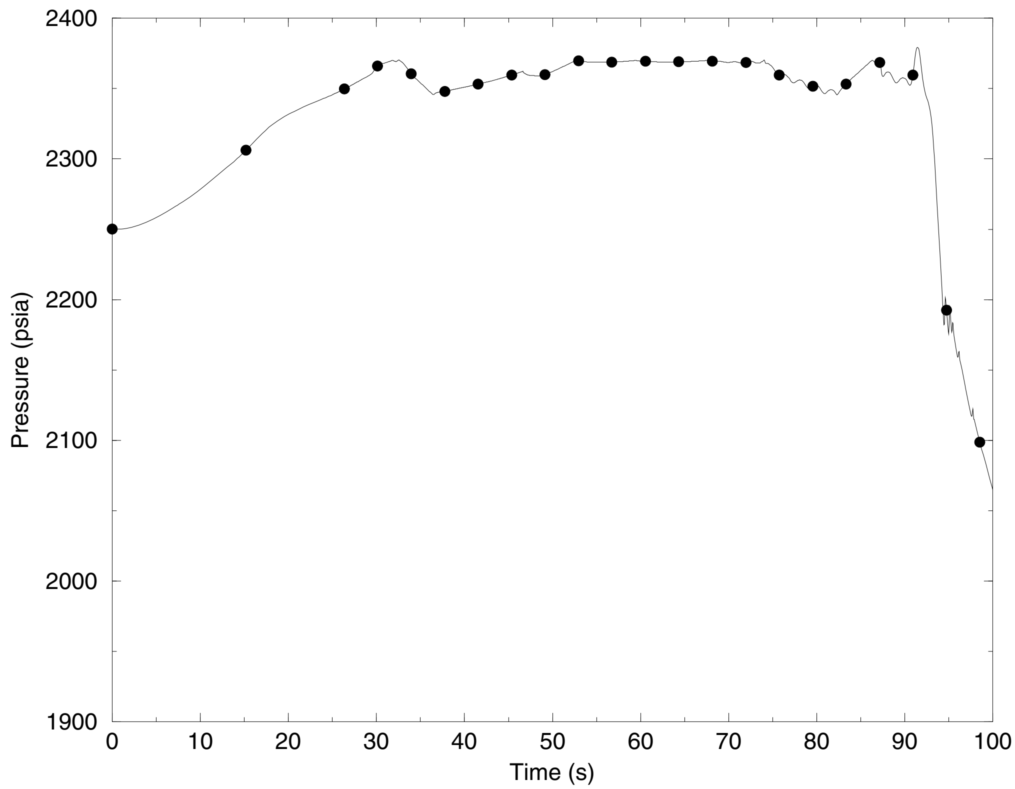


Figure 2.8.5.4.2-11
(SAFDL Case)
(EOC, 9.6 pcm/sec)
Pressurizer Liquid Level

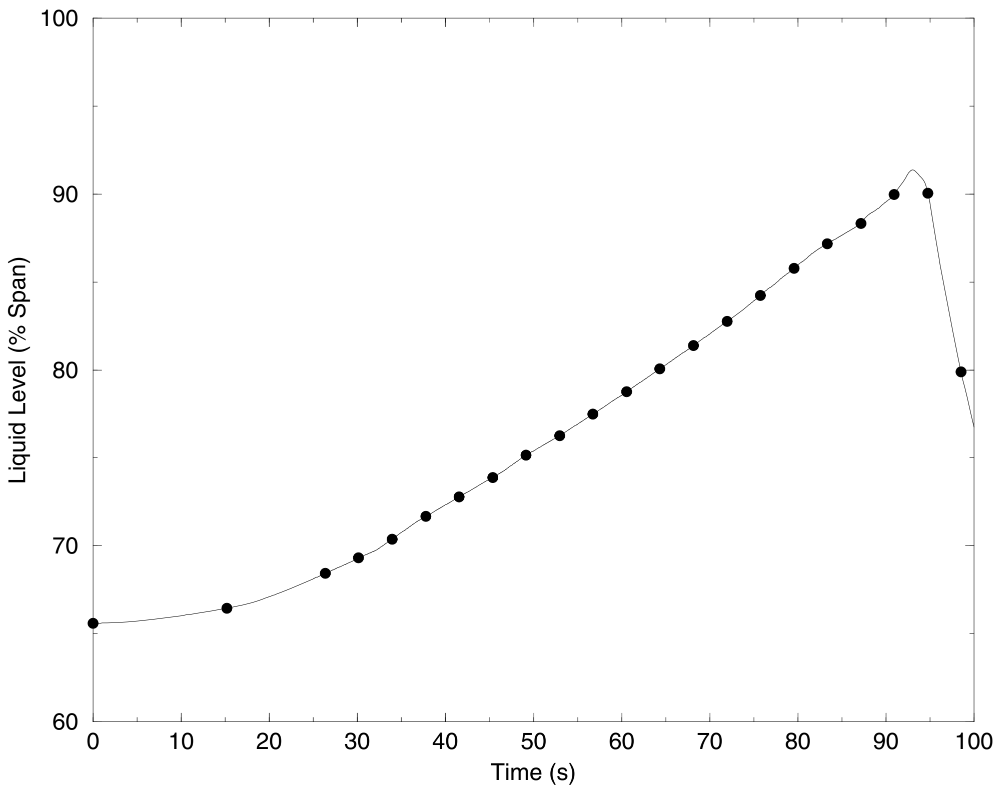


Figure 2.8.5.4.2-12
(SAFDL Case)
(EOC, 9.6 pcm/sec)
RCS Loop Temperatures

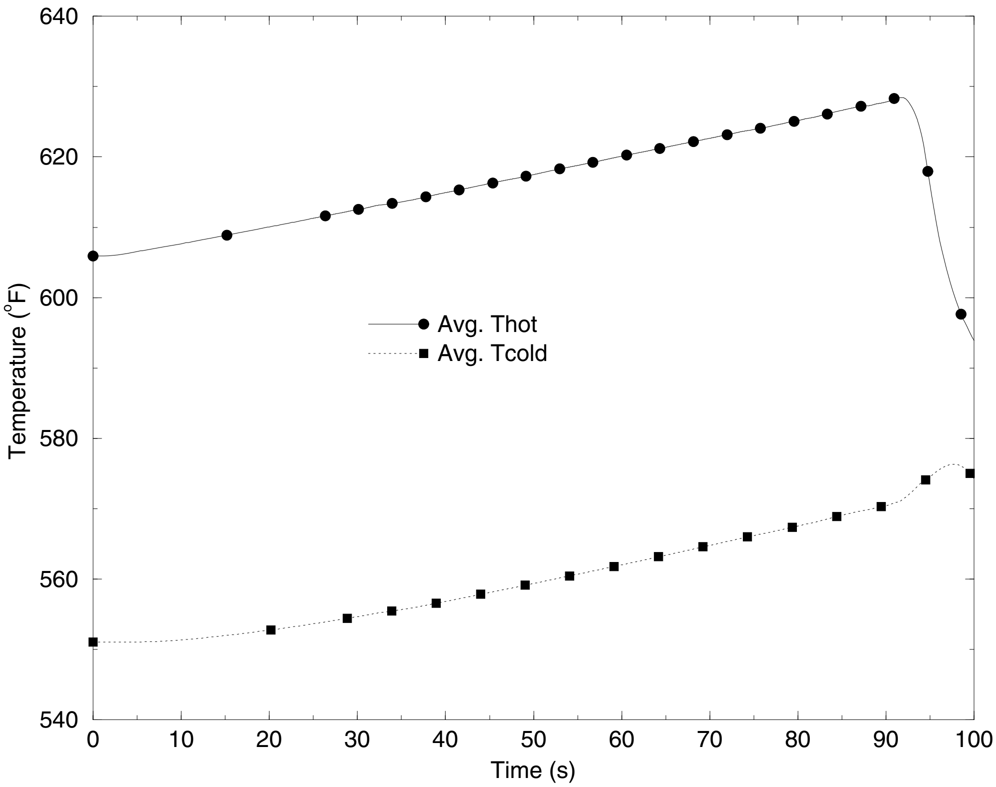


Figure 2.8.5.4.2-13
(SAFDL Case)
(EOC, 9.6 pcm/sec)
RCS Total Loop Flow Rate

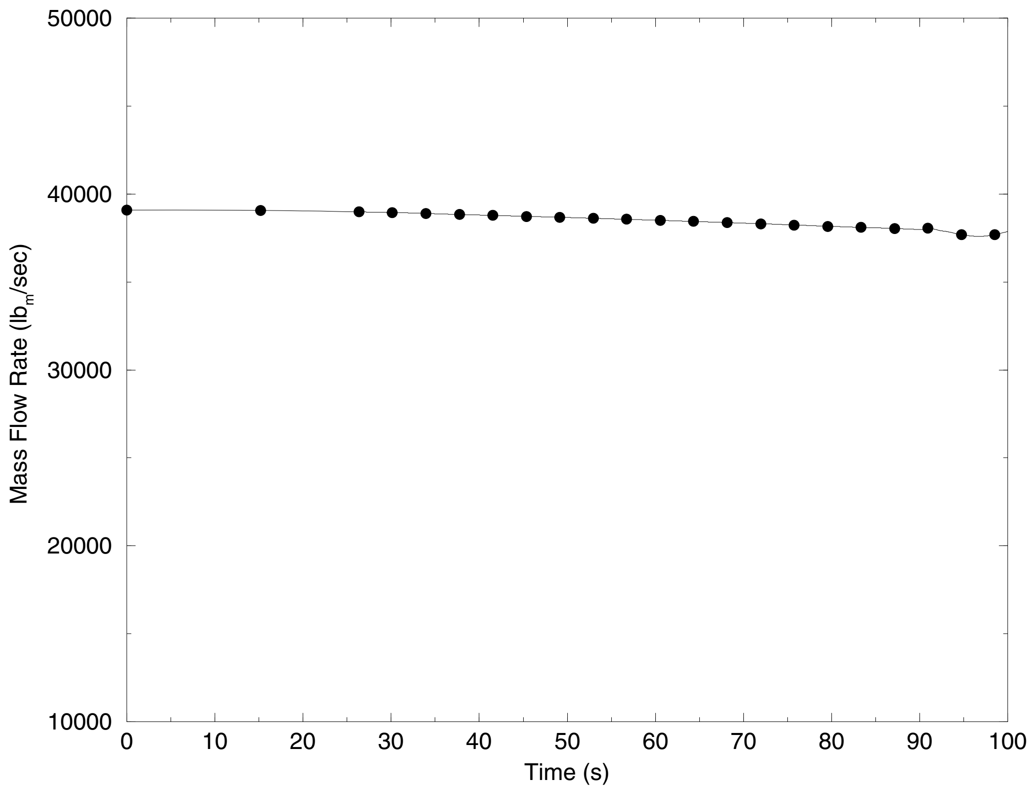


Figure 2.8.5.4.2-14
(SAFDL Case)
(EOC, 9.6 pcm/sec)
Reactivity Feedback

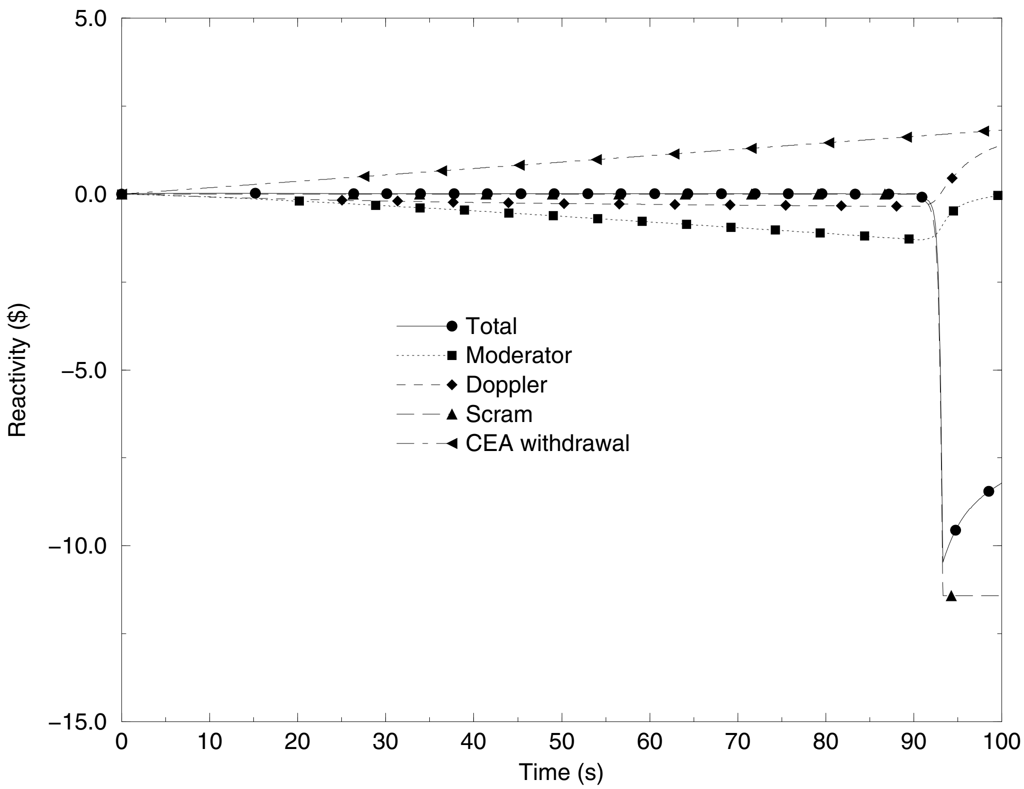


Figure 2.8.5.4.2-15
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
Reactor Power

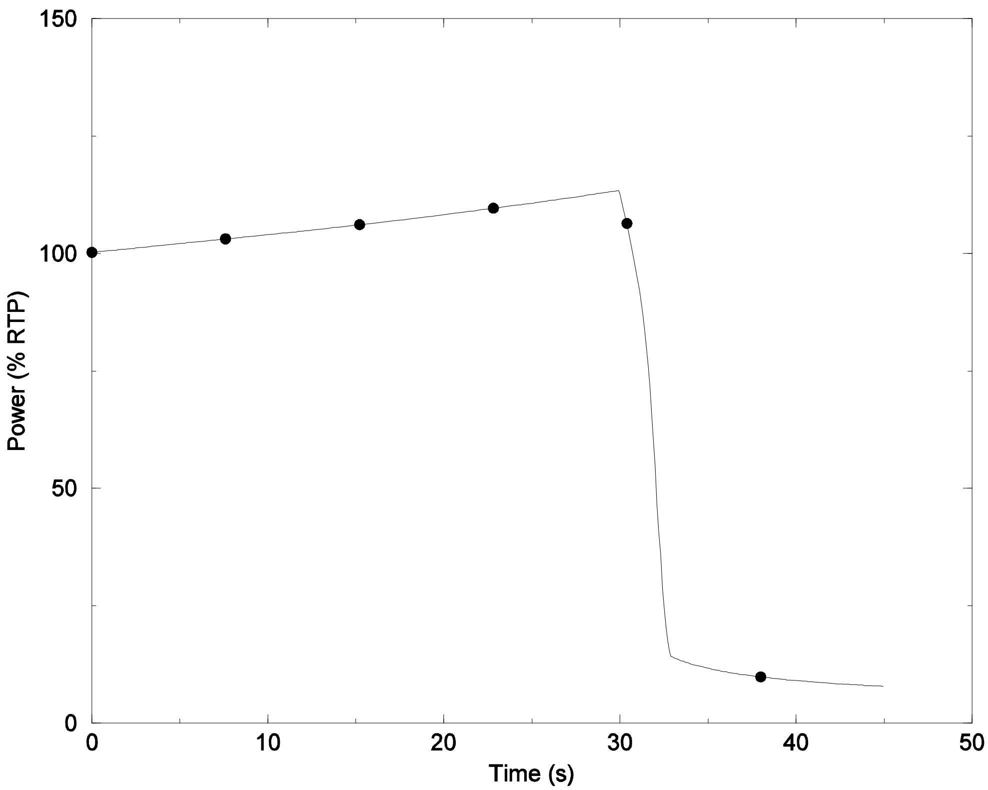


Figure 2.8.5.4.2-16
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
Pressurizer Pressure

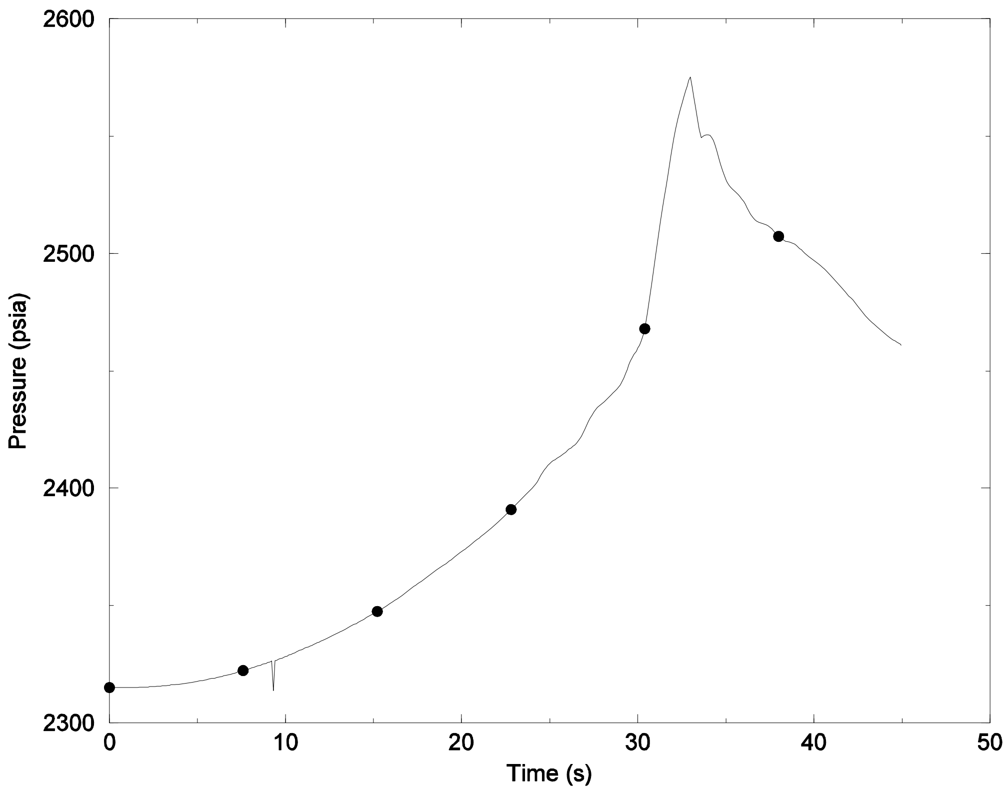


Figure 2.8.5.4.2-17
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
Pressurizer Liquid Level

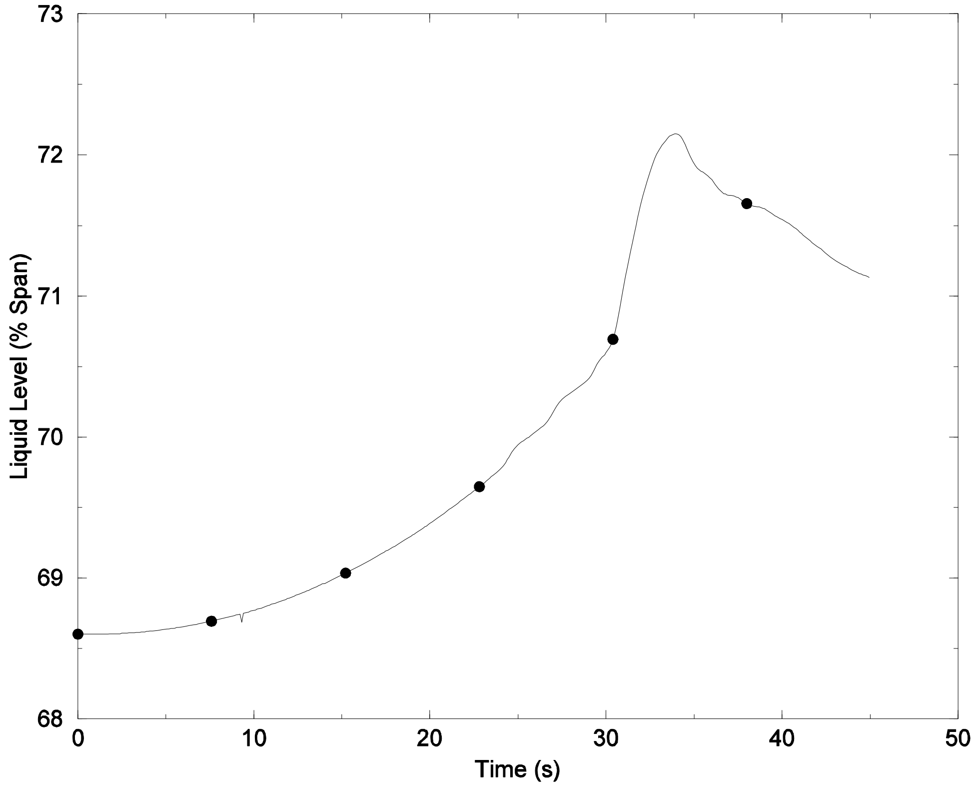


Figure 2.8.5.4.2-18
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
RCS Loop Temperatures

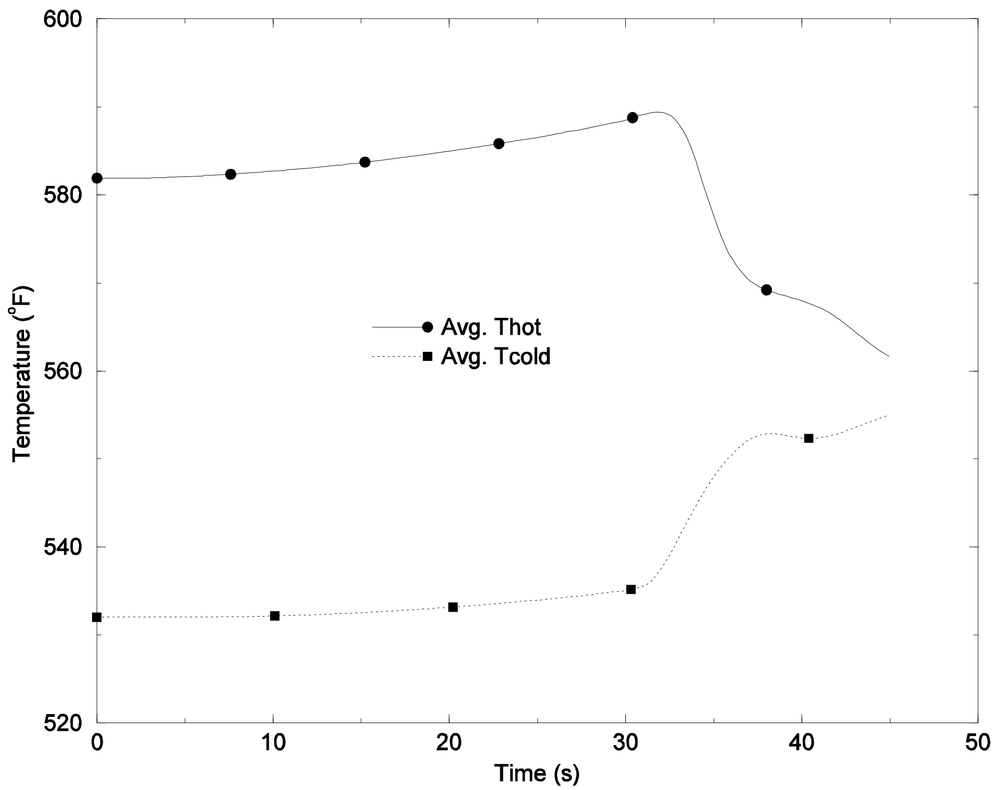


**Figure 2.8.5.4.2-19
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
RCS Total Loop Flow Rate**

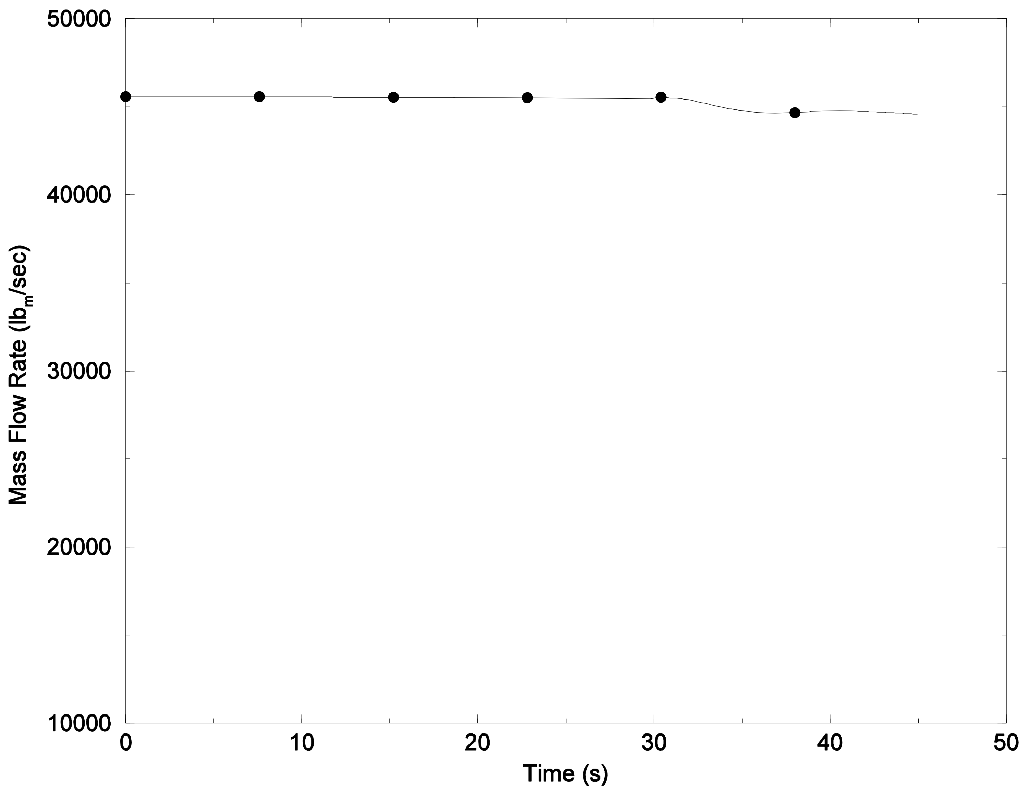


Figure 2.8.5.4.2-20
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
Reactivity Feedback

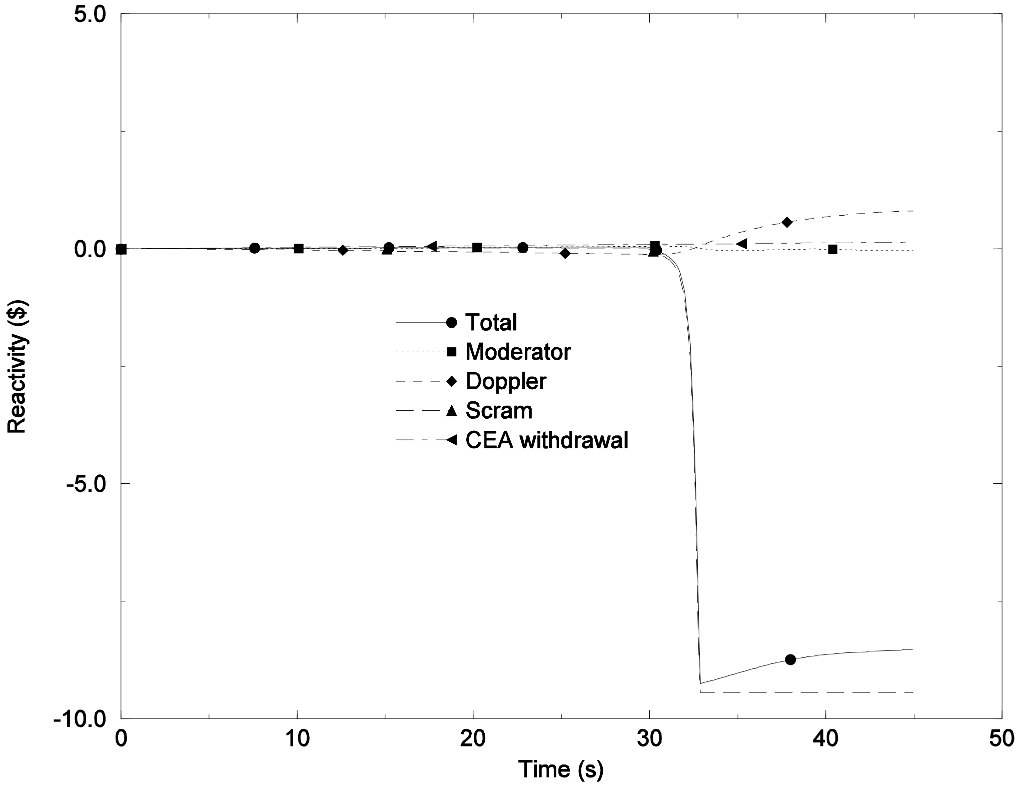
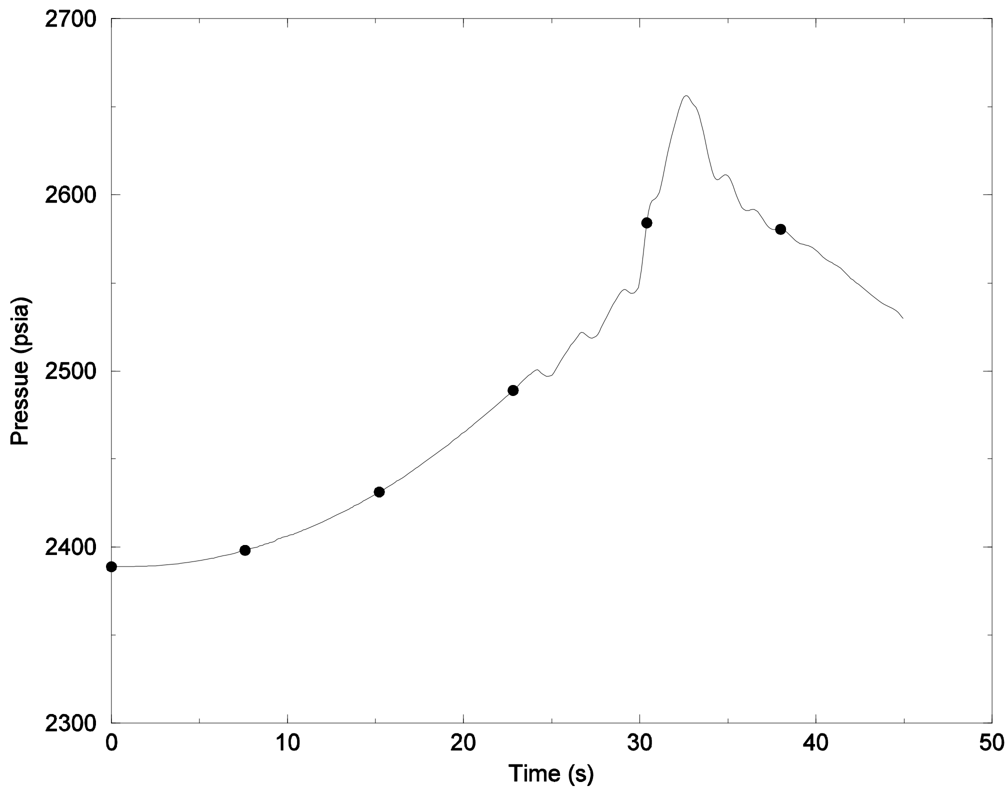


Figure 2.8.5.4.2-21
Uncontrolled CEA Withdrawal at Power (Maximum RCS Pressure Case)
(BOC, 2.033 pcm/sec)
Peak RCS Pressure



2.8.5.4.3 Control Rod Misoperation

2.8.5.4.3.1 Regulatory Evaluation

FPL's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error.

FPL's review covered:

- Descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) 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:

- 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 SAFDLs are not exceeded as a result of AOOs and to initiate automatically 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.4.3 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the control rod misoperation events 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. (Refer to UFSAR Section 7.2 and Chapter 15.)

SAFDLs are stated in Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and Limiting Conditions for Operations (LCOs)) 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 protective system 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 acceptable fuel design limits to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features (ESF) actuation system 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.

- 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 Sections 15.2.1 and 15.2.2. The reactor protection system (RPS) will prevent SAFDLs from being exceeded for any anticipated transients.

Discussion of the control rod misoperation event is provided in UFSAR Section 15.2.3.

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.

2.8.5.4.3.2 Technical Evaluation

2.8.5.4.3.2.1 Introduction

The CEA drop event is defined as the inadvertent release of a CEA causing it to drop into the core. A dropped CEA will be detected by either a position limit switch on each CEDM or by a reduction in power as measured by the ex-core detectors.

The negative reactivity insertion when the CEA drops into the core causes a reduction in the core power and reactor coolant temperatures. The magnitude of the decrease in core power and RCS temperatures depends on the worth of the dropped CEA. At end of cycle (EOC) conditions, a strongly negative moderator temperature coefficient (MTC) will produce a positive reactivity insertion that can return the reactor to the full-power condition with elevated radial power peaking corresponding to the new radial power distribution caused by the dropped CEA. Increased cladding heat fluxes and fuel temperatures in the hot assembly result in a challenge to the departure from nucleate boiling (DNB) and fuel centerline melt (FCM) SAFDLs.

The event analysis accounts for the changes in power distribution by applying radial peaking augmentation factors. For a given dropped CEA worth, there is a tradeoff between the resultant return-to-power and the radial peaking augmentation factor. A lower worth dropped CEA will result in a higher resultant peak power level, but a lower radial peaking augmentation factor. A higher worth dropped CEA will result in a lower resultant peak power level, but a higher radial peaking augmentation factor.

Protection against exceeding the SAFDLs is provided by the combination of the initial steady-state margin to DNB (defined by maintaining the axial shape index (ASI) and power within the DNB LCO band), the variable high power trip (VHPT), and the thermal margin/low pressure (TM/LP) trip. Depending on the dropped CEA worth, the event may be terminated by a reactor trip, or there may be no reactor trip and the plant returns to some final steady power level. Other than the RPS, no other automatic functions were credited that would mitigate this event. No single active failure will adversely affect the consequences of this event.

2.8.5.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 1 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – This event was assumed to initiate from hot full power (HFP) conditions with a maximum core inlet temperature and TS minimum RCS flow. This set of conditions minimizes the initial margin to DNB.
- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. The MTC was set to the most negative TS/core operating limits report (COLR) value to produce the most positive moderator reactivity feedback due to a dropped CEA.
- Dropped CEA Worth – A conservatively bounding range of dropped CEA worth was analyzed to determine the most limiting combination of worth and radial peaking augmentation.
- Gap Conductance – Gap conductance was set to a conservative EOC value to be consistent with the time-in-cycle for the reactivity coefficients.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The principally challenged acceptance criterion for this event is:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

This criterion is met by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the 95/95 DNB correlation limit. Additionally, FCM is demonstrated to be precluded in the most adverse location in the core.

2.8.5.4.3.2.3 Description of Analyses and Evaluations

Detailed analyses were performed with approved non-LOCA methodology given in Reference 1. For this event, the S-RELAP5 code was used to model the key system response and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of minimum departure from nucleate boiling ratio (MDNBR). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 2), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 3). Evaluation of the dropped CEA event was performed as part of the DNB LCO analyses (LR Section 2.8.5.0.13) using the Reference 4 methodology.

Calculations were performed at EOC HFP conditions, maximum TS core inlet temperature, and minimum TS RCS flow rate. This produces the minimum margin to the DNB limit. The event was analyzed with the most negative HFP MTC, which results in the most positive moderator reactivity feedback as the RCS cools down due to the dropped CEA.

A range of dropped CEA worth was analyzed to conservatively bound possible combinations of the maximum return-to-power and the radial peaking augmentation factor associated with any given dropped CEA worth.

2.8.5.4.3.2.4 Evaluation of 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 extended power uprate (EPU) does not impact any License Renewal evaluations.

2.8.5.4.3.2.5 Results

The sequence of events is given in LR Table 2.8.5.4.3-1. Results are given in LR Table 2.8.5.4.3-2. Since the thermal power changes are not significant, the VHTP setpoint is not reached, and thus, no reactor trip occurs. Without the occurrence of a reactor trip in any of the cases, the power asymptotically reaches a new steady value. Thus, the maximum core power was calculated to be 3033.5 MWt and is reported at the end of the calculations, when there is no significant increase in core power and no significant change in any of the parameters that are input to the DNBR calculations. The limiting MDNBR with deterministically applied uncertainties was calculated to be 1.566, which is above the 95/95 limit of 1.164 for the HTP CHF correlation. The peak linear heat rate (LHR) was calculated to be 20.750 kW/ft, which is less than the FCM limit of 22.279 kW/ft. Statistical evaluation of this event was performed as part of the DNB LCO analyses (LR Section 2.8.5.0.13).

The transient response is shown in LR Figures 2.8.5.4.3-1 through 2.8.5.4.3-9. LR Figure 2.8.5.4.3-1 shows the core power, nuclear instrumentation (NI) detected power, and the thermal power as a function of time. LR Figure 2.8.5.4.3-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.4.3-3 through 2.8.5.4.3-9 show the pressurizer pressure, the pressurizer liquid level, the RCS loop temperatures, the total RCS flow rate, the steam generator pressures, the steam flow rates, and the reactivity feedback, respectively.

2.8.5.4.3.3 Conclusion

FPL has analyzed control rod 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 analysis has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipate operational transients. 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 control rod misoperation events.

2.8.5.4.3.4 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

4. EMF-1961(P)(A), Revision 0, Statistical/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

Table 2.8.5.4.3-1
CEA Drop
Sequence of Events

Case	Event	Time (sec.)
200 pcm	Rod drop initiated	0.0
	Minimum core power	3.0
	Maximum return-to-power	300.0

Table 2.8.5.4.3-2
CEA Drop
Results

Criterion	EPU Analysis	Limit
MDNBR	1.566	1.164
Peak LHR (kW/ft)	20.750	22.279

Figure 2.8.5.4.3-1
CEA Drop (200 pcm)
Reactor Power

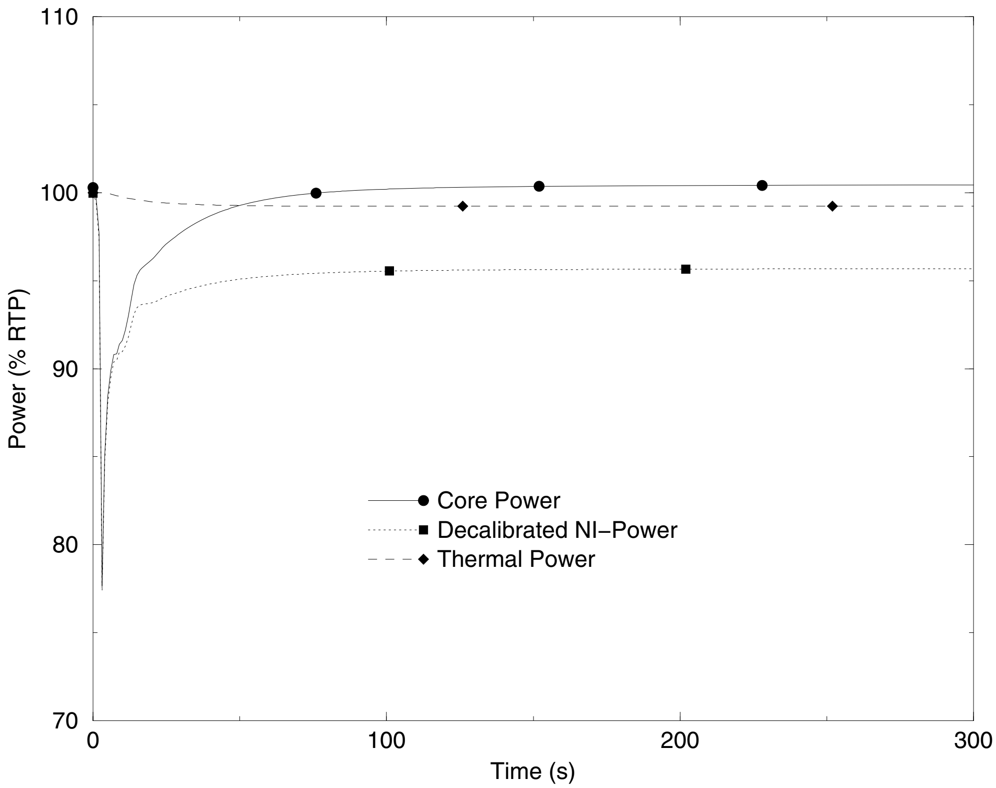


Figure 2.8.5.4.3-2
CEA Drop (200 pcm)
Total Core Heat Flux Power

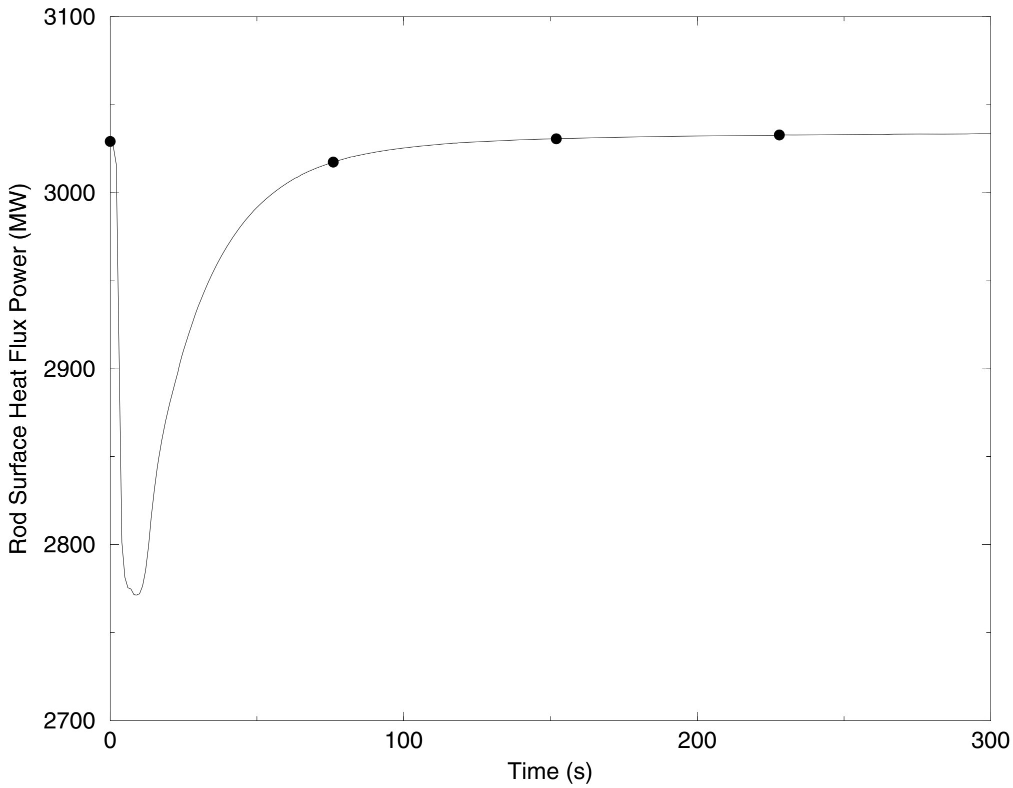


Figure 2.8.5.4.3-3
CEA Drop (200 pcm)
Pressurizer Pressure

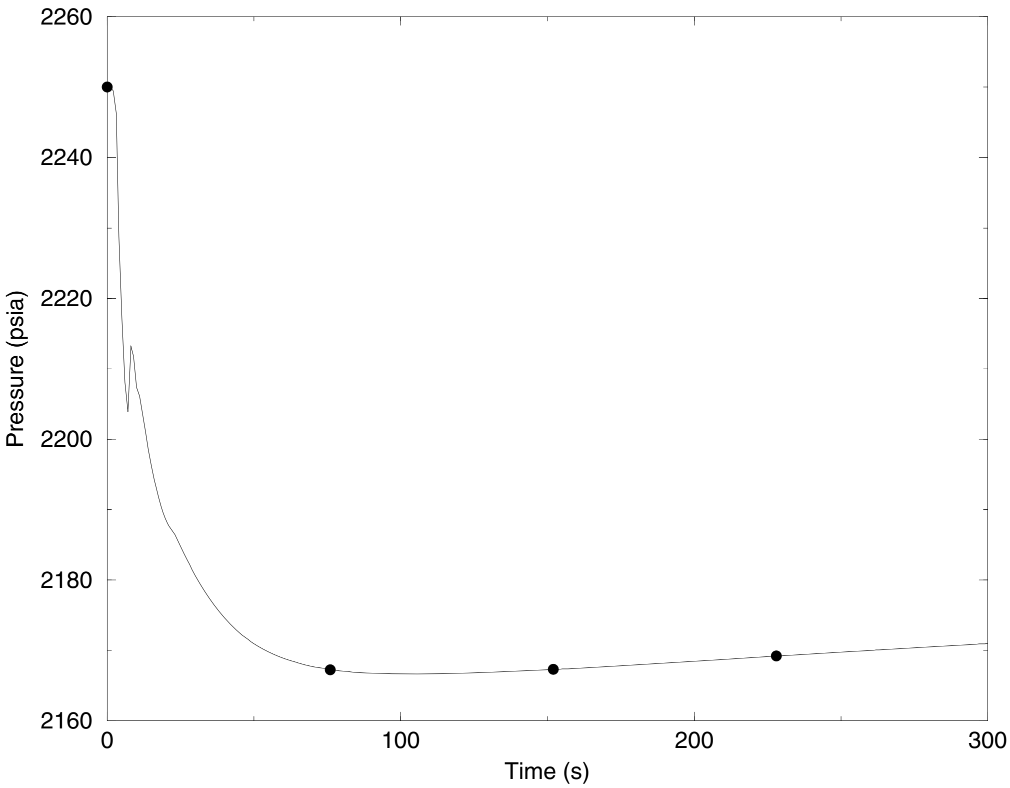


Figure 2.8.5.4.3-4
CEA Drop (200 pcm)
Pressurizer Liquid Level

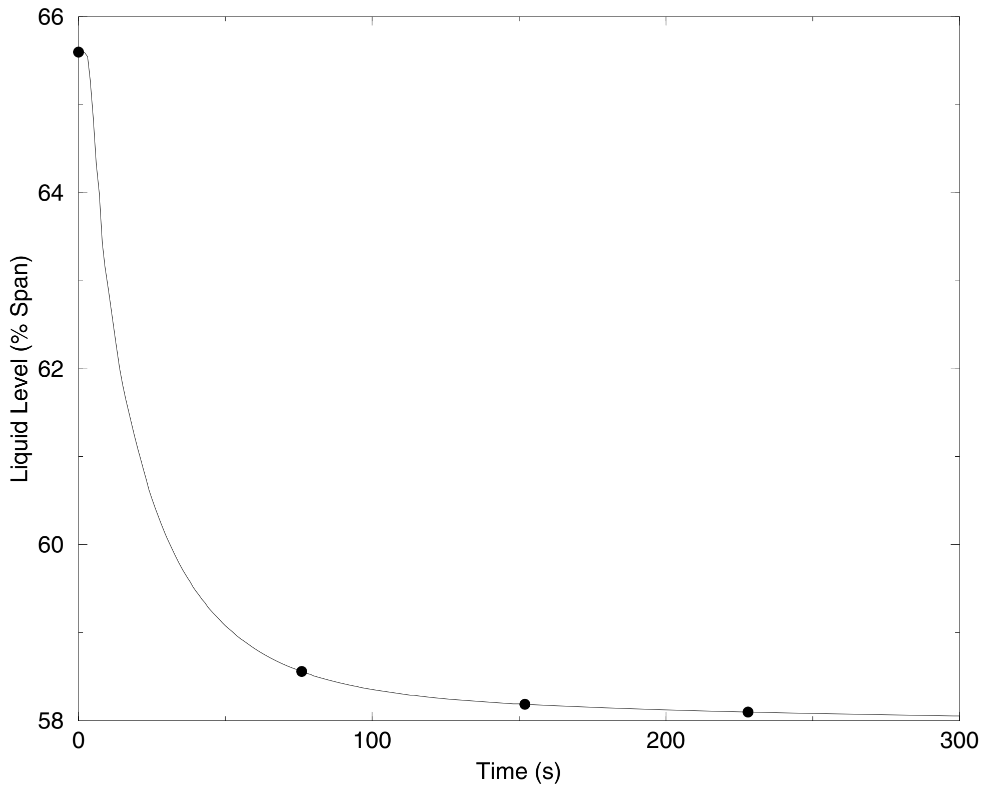


Figure 2.8.5.4.3-5
CEA Drop (200 pcm)
RCS Loop Temperatures

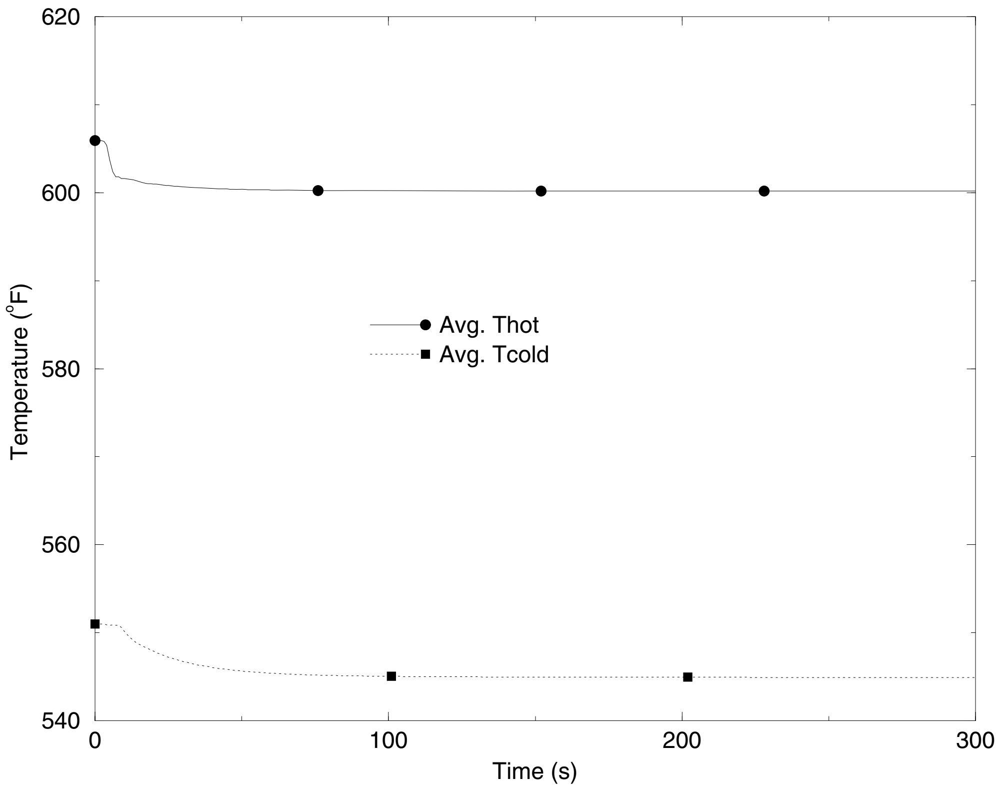


Figure 2.8.5.4.3-6
CEA Drop (200 pcm)
RCS Total Loop Flow Rate

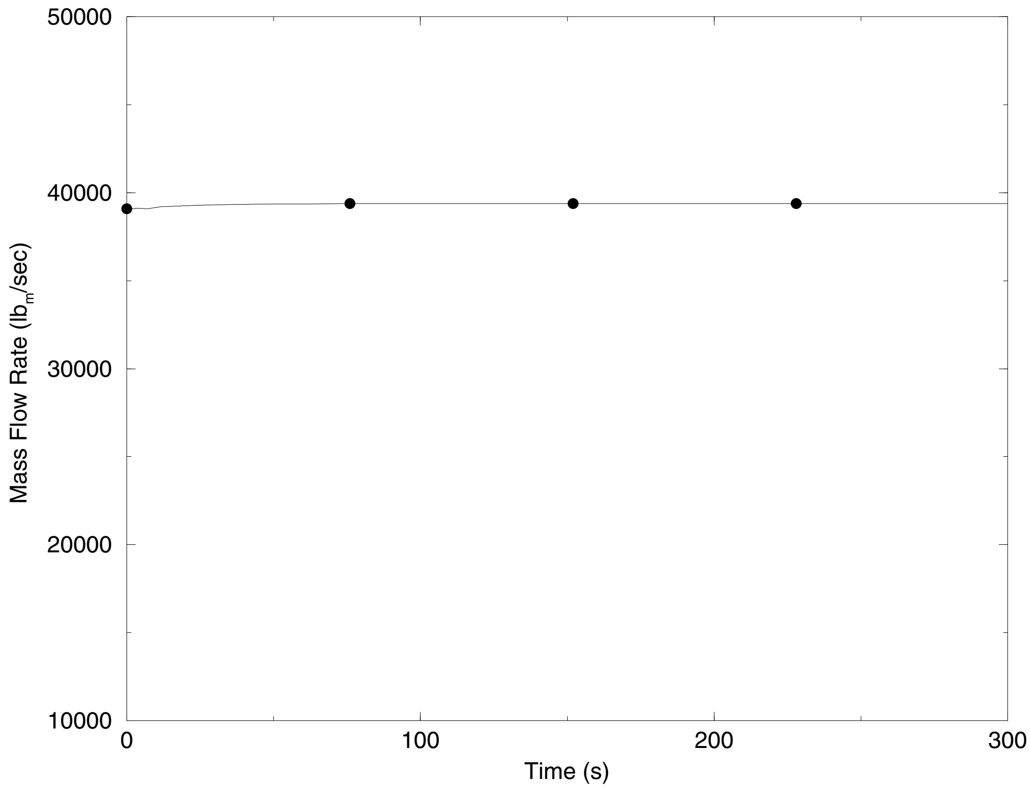


Figure 2.8.5.4.3-7
CEA Drop (200 pcm)
Steam Generator Pressures

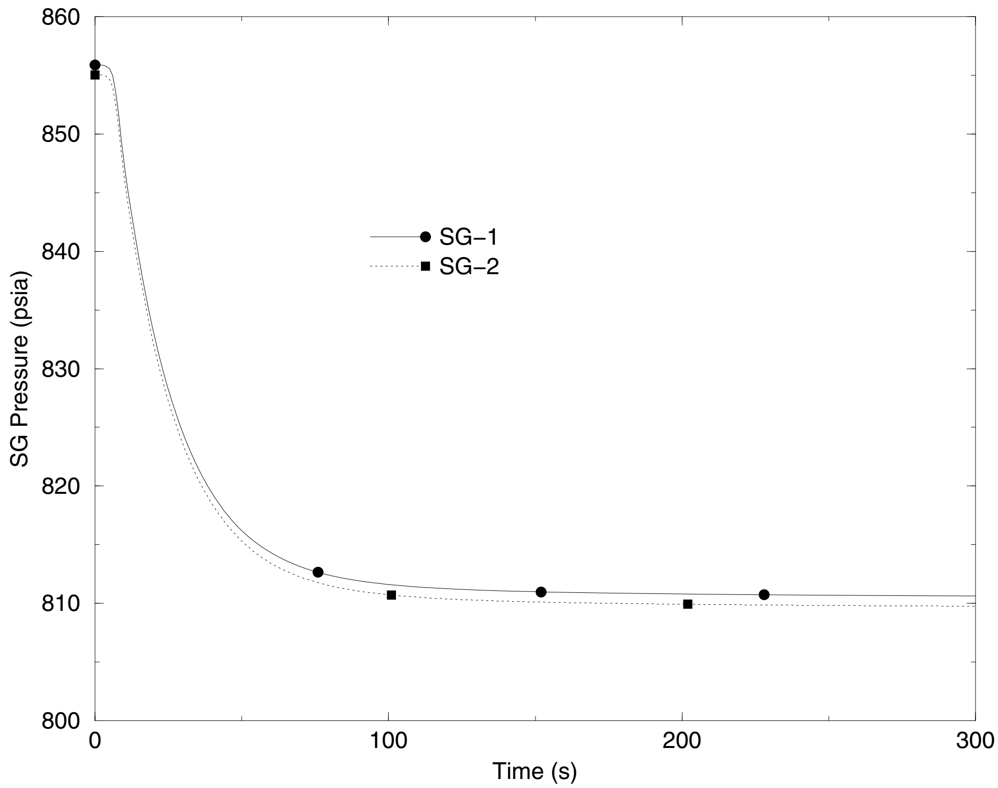


Figure 2.8.5.4.3-8
CEA Drop (200 pcm)
Steam Flow Rates

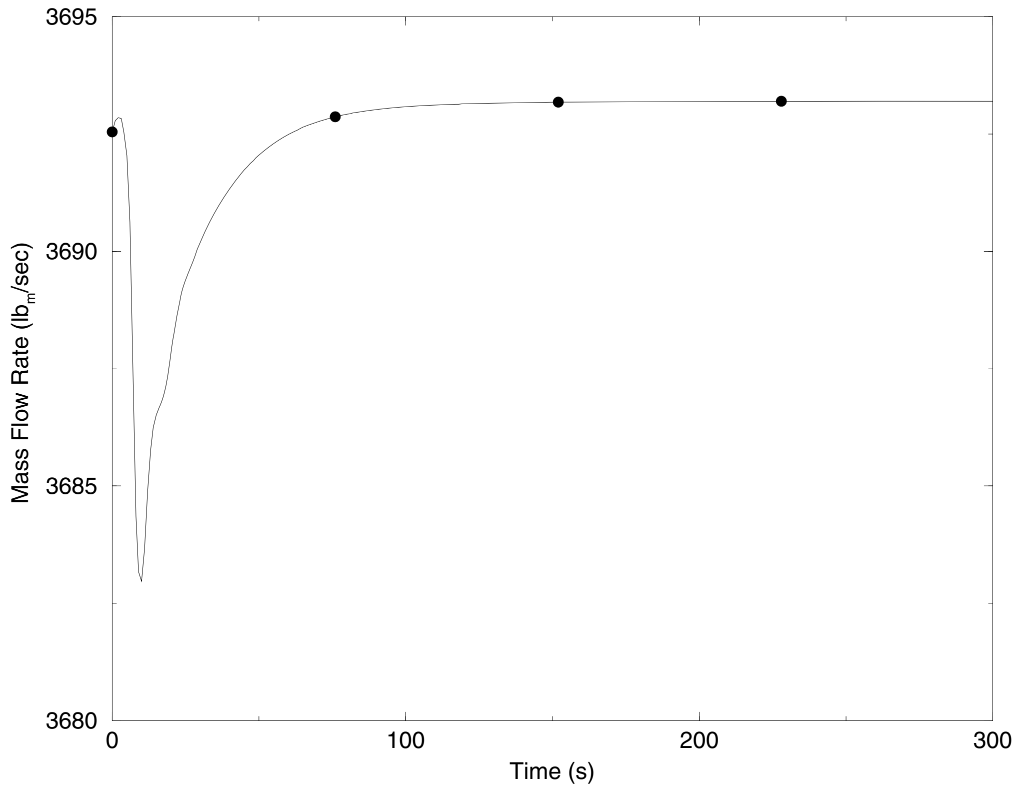
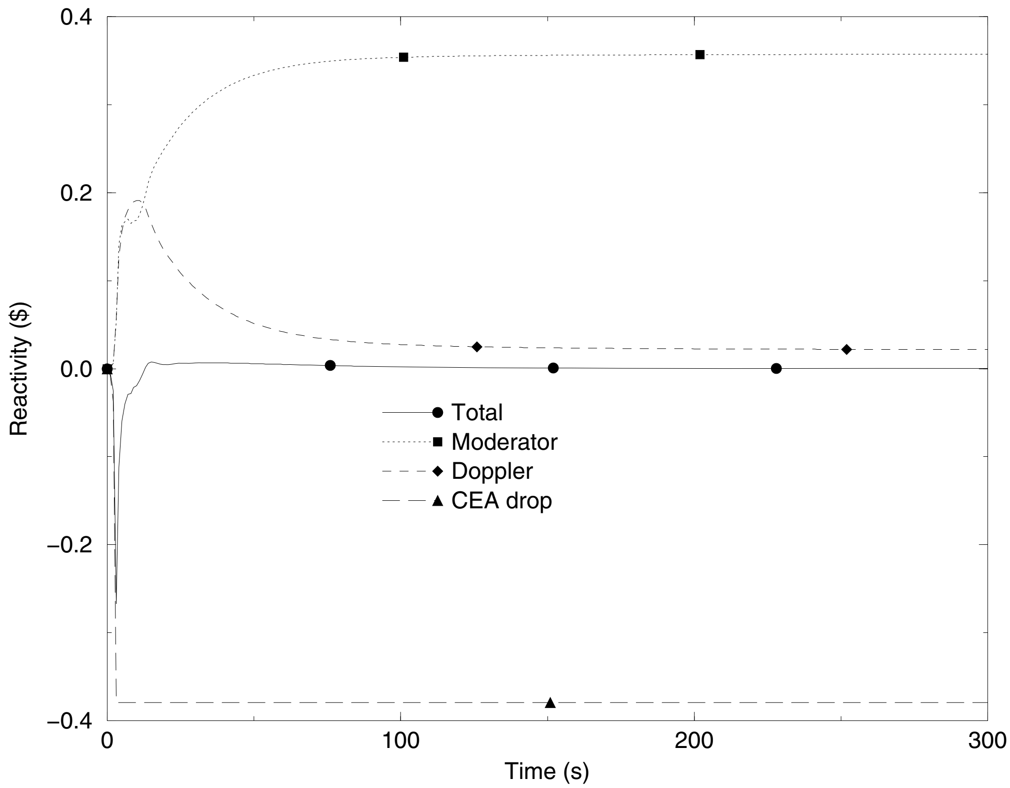


Figure 2.8.5.4.3-9
CEA Drop (200 pcm)
Reactivity Feedback



2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Technical Specifications limiting condition for operation (LCO) 3.4.1.1 states that in Modes 1 and 2, both reactor coolant loops and both reactor coolant pumps in each loop shall be in operation. Thus, this event is precluded by Technical Specifications, is not in the current licensing basis for St. Lucie Unit 1, and no analysis was performed.

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.

FPL's 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 NRC's 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 SRP Section 15.4.6 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR

(Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the CVCS malfunction that results in a decrease in boron concentration in the reactor coolant 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protective system (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of any AOO.

- 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 controlling reactivity changes to assure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding the reactor subcritical under cold conditions-Refer to UFSAR Section 9.3.4 for details.

Discussion of the CVCS malfunction event that results in a decrease in boron concentration in the RCS is provided in UFSAR Section 15.2.4.

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.

2.8.5.4.5.2 Technical Evaluation

2.8.5.4.5.2.1 Introduction

CVCS regulates both the chemistry and the quantity of coolant in the RCS. Changing the boron concentration in the RCS is a part of normal plant operation, compensating for long term reactivity effects, such as fuel burnup, xenon buildup and decay, and plant startup and cooldown. For refueling operations, borated water is supplied from the refueling water tank (RWT), which assures adequate shutdown margin. An inadvertent boron dilution in any operational mode adds positive reactivity, produces power and possibly temperature increases, and, in Modes 1 and 2 (startup and power operations) can cause an approach to both the departure from nucleate boiling ratio (DNBR) and fuel centerline melt (FCM) limits.

Boron dilution is conducted under strict administrative procedures, which specify permissible limits on the rate and magnitude of any required change in boron concentration. Boron concentration is determined by sampling the RCS.

Dilution of the reactor coolant can be terminated by isolation of the makeup water system, by stopping either the makeup water pumps or the charging pumps, or by closing the charging isolation valves. A charging pump must be running in addition to a makeup water pump for boron dilution to take place. CVCS is equipped with the following indications and alarm functions, which will inform the reactor operator when a change in boron concentration in the reactor coolant system may be occurring:

- Volume control tank (VCT) level indication and high and low alarms

- Makeup flow indication and alarms
- Volume control tank isolation.

In addition to the above, a boron dilution alarm is provided by the excore neutron flux monitoring system.

To assist the reactor operator in maintaining an adequate shutdown margin, CEA insertion below a position that would provide a minimum of one percent shutdown margin (assuming one stuck CEA) is accompanied by control room alarms. Because of the procedures involved and the numerous alarms and indications available to the operator, the probability of a sustained or erroneous dilution is very low.

2.8.5.4.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The input parameters are shown in LR Table 2.8.5.4.5-1.

The calculated time-to-criticality is dependent on the critical-to-initial boron concentration ratio, the RCS coolant volume/mass, and the flow rate of the boron dilution stream. In addition, for the dilution front model, a range of shutdown cooling system (SDCS) flow rates is evaluated. The initial boron concentration for each Operating Mode is defined such that shutdown margin requirements are satisfied. For Modes 5 and 6, a conservative RCS volume corresponding to mid-loop conditions is used. The sweepout volume, also used for Modes 5 and 6, covers the system volume from the SDCS valve location to the core inlet.

A conservative dilution time constant was used that assumed not only a conservative average steam generator tube plugging (SGTP) of 15%, but also the availability of three charging pumps for all modes. In each case, it is also assumed that the boron dilution results from pumping unborated demineralized water into the RCS at the maximum possible rate of 147 gpm (3×49 gpm per charging pump).

The acceptance criteria for Modes 2 through 6 are that the time to criticality allows operator action to terminate the event. The required time to operator action for Modes 2 through 5 is 15 minutes. The required time to operator action for Mode 6 is 30 minutes.

2.8.5.4.5.2.3 Description of Analyses and Evaluation

Cases have been considered for all six operational modes, i.e., power operation, startup, hot standby, hot shutdown, cold shutdown, and refueling. The boron dilution event was analyzed with the approved Reference 1 methodology which is the same as that used for the current analysis.

An inadvertent boron dilution adds positive reactivity, produces power and temperature increases, and during operation at power (Mode 1) can cause an approach to both the DNBR and FCM limits. Since the thermal margin/low pressure (TM/LP) trip system monitors the transient behavior of core power level and core inlet temperature at power, the TM/LP trip will intervene, if necessary, to prevent the DNBR limit from being exceeded for power increases within the setting of the variable high power level trip (VHPT). Mode 1 boron dilution event is bounded by the reactivity insertion rates considered in the CEA Withdrawal at Power event (LR Section 2.8.5.4.2, Uncontrolled Rod Cluster Control Assembly Withdrawal at Power).

In the event of an unplanned dilution during Mode 2 power escalation, the plant status is such that minimal impact will result. The plant will slowly escalate in power and activate a power-related trip (TM/LP or VHPT). The acceptance criteria for Mode 2 must provide sufficient time to prevent a return to criticality. Prior to trip, challenges to the departure from nucleate boiling (DNB) and FCM SAFDLs are bounded by other events, such as CEA Withdrawal at Startup or Low Power (LR Section 2.8.5.4.1, Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low-Power Startup Condition).

Two models were used to evaluate the boron dilution transient,

- instantaneous mixing model, and
- dilution front model.

The instantaneous mixing model is applicable when at least one reactor coolant pump (RCP) is operating and assumes the unborated water is instantaneously mixed with the entire water volume in the RCS. The dilution front model is used when the core is being cooled by the SDCS (no RCPs operating); for these operating modes the RCS flow is much lower than operating with a RCP and the assumption of instantaneous mixing of the unborated water with the entire RCS volumes is not valid.

2.8.5.4.5.2.4 Evaluation of 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

LR Table 2.8.5.4.5-2 shows the results from the boron dilution event. Results from the previous analysis are also provided in LR Table 2.8.5.4.5-2. Differences in results between the previous analysis and the EPU analysis are primarily due to differences in the initial and critical boron concentrations, which are dependent on the core design.

The results of the instantaneous mixing model show that there is adequate time to operator action prior to a complete loss in shutdown margin for Modes 2, 3, and 4.

The results of the dilution front model show that there is adequate time to operator action prior to a significant loss in shutdown margin provided the SDCS flow rate is maintained at or above the limits shown in LR Table 2.8.5.4.5-2.

The boron dilution event requirements are verified each refueling cycle using cycle-specific initial and critical boron concentrations.

2.8.5.4.5.3 Conclusion

FPL has analyzed the decrease in boron concentration in the reactor coolant due to a CVCS malfunction 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 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. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

Table 2.8.5.4.5-1
CVCS Malfunction/Boron Dilution
Input Parameters

Parameter	(Critical/Initial for limiting case) Boron concentration ppm	Boron Ratio
Startup (Mode 2)	1157/1506	0.768
Hot Standby (Mode 3)	1157/1506	0.768
Hot Shutdown (Mode 4)	1172/1498	0.782
Cold Shutdown (Mode 5)	1180/1449	0.815
Refueling (Mode 6)	1620/2069	0.783
Charging flow, gpm per pump	49	–
Number of charging pumps	3	–
Partial RCS volume, ft^3	3616	–
Full RCS volume, ft^3	8303	–
Sweepout volume, ft^3	1717	–

Table 2.8.5.4.5-2
CVCS Malfunction/Boron Dilution
Results

Parameter	Operator Required Response Time (minutes)	Previous Analysis		EPU Analysis	
		Time-to-Criticality (minutes)	SDCS Min. Flow (gpm)	Time-to-Criticality (minutes)	SDCS Min. Flow (gpm)
Instantaneous Mixing Model					
Startup (Mode 2)	15	85.36	N/A	84.98	N/A
Hot Standby (Mode 3)	15	85.36	N/A	84.98	N/A
Hot Shutdown (Mode 4)	15	93.88	N/A	93.83	N/A
Dilution Front Model					
Hot Shutdown (Mode 4)	15	28.40	780	28.36	780
Cold Shutdown (Mode 5)	15	22.42	780	25.46	780
Refueling (Mode 6)	30	41.12	3000	39.56	3000

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. 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:

- The initial conditions,
- The rod patterns and worths, scram worth as a function of time, and reactivity coefficients,
- The analytical model,
- The core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to impair significantly the capability to cool the core.

Specific review criteria are contained in SRP Section 15.4.8 and other guidance provided in Matrix 8 of RS-001, Revision 0.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

The GDC relevant to the spectrum of rod ejection accidents is:

- 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 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 control element assembly (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 minimum value. The CEAs are divided into shutdown groups and regulating groups. Administrative procedures and interlocks ensure that only one group is withdrawn at a time, and that 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 7.1.1.

The maximum rate of reactivity addition which may be produced by the chemical and volume control system (CVCS) is too low to induce any significant pressure forces which might degrade the RCPB leak tightness integrity or disturb the reactor vessel internals. UFSAR Section 9.3.4 describes the design bases of the CVCS.

The RCPB described in UFSAR Chapter 5 and the reactor vessel internals described in UFSAR Chapter 4 can 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 15.4.5.

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 control rod (CEA) ejection event is initiated by a postulated rupture of a control rod drive mechanism housing. Such a rupture allows the full system pressure to act on the drive shaft, which ejects its control rod from the core. The consequences of the mechanical failure are a rapid positive reactivity insertion and an increase in radial power peaking, which could possibly lead to localized fuel rod damage.

Doppler reactivity feedback mitigates the power excursion as the fuel begins to heat up. Although the initial increase in power occurs too rapidly for the scram rods to have any significant effect on the power during that portion of the transient, the scram negative reactivity insertion does affect the fuel temperature and fuel rod cladding surface heat flux.

The ejected rod causes localized peaking such that fuel failure may occur due to departure from nucleate boiling (DNB) or fuel centerline melt (FCM). The reactor coolant system (RCS) pressure increases for this event which may challenge the overpressure criterion.

2.8.5.4.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 1 methodology.

- Initial Conditions - The analysis was performed from both hot full power (HFP) and hot zero power (HZP) initial conditions to provide a bounding fuel response to the ejected CEA. Respective maximum core inlet temperatures were assumed for each initial condition. Technical Specification (TS) minimum RCS flow rate was modeled.
- Reactivity Feedback - Reactivity feedbacks were modeled that represented beginning of cycle (BOC) and end of cycle (EOC) conditions. Due to the rapidity of the transient, moderator feedback has a second-order impact on the consequences. TS/core operating limits report (COLR) moderator temperature coefficient (MTC) limits were modeled for the cases initiated at BOC, whereas conservatively biased “least negative” MTCs were modeled for the EOC cases. The event is initially mitigated by the negative Doppler reactivity feedback. As such, the Doppler reactivity assumed in the analysis was conservatively biased to minimize the negative feedback due to increasing fuel temperatures. For the HZP initiated cases, fuel temperature dependent Doppler feedback was modeled.
- Reactor Protection System (RPS) Trips and Delays - The event is primarily protected by the variable high power trip (VHPT). The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion is delayed to account for the CEA holding coil delay time.
- Ejected CEA Worth - To maximize the core power response to the ejected CEA, a conservatively high ejected CEA worth was assumed for each case, based on St. Lucie Unit 1 specific rod patterns and power-dependent insertion limits.
- Gap Conductance – Depending on the time-in-cycle for the reactivity coefficients, gap conductance was set to either a conservative BOC value or a conservative EOC value to maximize the heat flux through the cladding and minimize the negative reactivity inserted due to Doppler feedback.
- Single Failure - Since the systems designed to mitigate this event (namely, the RPS) are redundant, there is no single active failure that will adversely affect the consequences of the event.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses, provides the SGTP level supported by the analyses.

The acceptance criteria for this event are the following:

- Fuel failures due to DNB and FCM should be limited, so as not to impair the capability to cool the core. Additionally, the fuel failures should be within the limits of fuel failures used in the radiological analysis.
- Reactivity excursions should not result in a radially averaged enthalpy greater than 280 cal/gm at any axial location in any fuel rod.

- The maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the faulted condition stress limits.
- Radiological consequences should be within the regulatory limits consistent with the design basis requirements.

2.8.5.4.6.2.3 Description of Analyses and Evaluations

CEA ejection analyses, supporting current plant operation, were performed with the approved methodology in (Reference 4). For the EPU, detailed thermal-hydraulic analyses were performed with approved methodology given in Reference 1. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), an estimated time of minimum departure from nucleate boiling ratio (MDNBR) and peak system pressures. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 2), which was used to calculate the MDNBR using the high thermal power (HTP) critical heat flux (CHF) correlation (Reference 3). Deposited enthalpy was calculated using the Reference 4 methodology.

Four cases are analyzed for the event: (1) HFP initial conditions at BOC, (2) HFP initial conditions at EOC, (3) HZP initial conditions at BOC and (4) HZP initial conditions at EOC. Per the TS, the core is held subcritical by more than 1% for Mode 3 (Hot Standby), Mode 4 (Hot Shutdown) and Mode 5 (Cold Shutdown). Since 1% is more than the worth of the ejected control rod, evaluation of these modes is not required. For this analysis, HZP is assumed to be Mode 2 (Startup).

All four reactor coolant pumps are assumed to be in operation in both Mode 1 (Power Operation) and Mode 2 (Startup).

While this postulated event could have a failure of the RCOB, it is not clear if (or to what extent) debris pulled toward the break by fluid flow would clog or block the break. Because of this uncertainty, conservative assumptions are typically used to bias the RCS pressure transient response. The evaluation of maximum RCS pressure for this event is based on a plugged hole in the head and takes no credit for pressure reduction from flow out the break. For evaluation of DNB, the RCS pressure is held constant at the initial value and is assumed to neither increase nor decrease.

2.8.5.4.6.2.4 Evaluation of 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

The sequence of events is shown in LR Table 2.8.5.4.6-1. Results are given in LR Tables 2.8.5.4.6-2 and 2.8.5.4.6-3. The peak hot spot centerline temperatures were calculated to be less than the fuel melt temperature; thus, no fuel failure is predicted to occur as a result of fuel centerline melting. MDNBR was calculated to be above the 95/95 CHF correlation limit; thus, no fuel failure is predicted to occur as a result of DNB. The deposited enthalpies were calculated to be less than the current UFSAR limit.

The BOC HFP case presented the most significant challenge to acceptance criteria. The transient response is shown in LR Figures 2.8.5.4.6-1 through 2.8.5.4.6-6. LR Figure 2.8.5.4.6-1 shows the reactor power as a function of time. LR Figure 2.8.5.4.6-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.4.6-3 through 2.8.5.4.6-6 show the RCS loop temperatures, the total RCS flow rate, the reactivity feedback, and the peak fuel centerline temperature, respectively.

The peak RCS pressure analysis is performed by biasing the input parameters in the conservative direction to maximize the RCS overpressure. The peak pressure results from the BOC HFP case and is calculated to be 2696 psia, which is bounded by the loss of external load event (LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum). The peak RCS pressure thus remains below the limit of 110% of design pressure. The sequence of events for the overpressure analysis is provided in LR Table 2.8.5.4.6-4 and the plot of RCS pressure as a function of time is presented in LR Figure 2.8.5.4.6-7.

Since no fuel failures are predicted, the fuel failure limits in the radiological dose analyses documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST) are met.

2.8.5.4.6.3 Conclusion

FPL has performed the rod ejection accident analyses and concludes that the analyses adequately account for operation of the plant at the proposed power level and the analyses 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 reactor coolant pressure boundary 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 the plant will continue to meet the requirements of GDC-28 following implementation of the proposed extended power uprate (EPU). Therefore, FPL finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.4.6.4 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

2. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

4. XN-NF-78-44(NP)(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, October 1983.

Table 2.8.5.4.6-1
CEA Ejection
Sequence of Events – Fuel Response

Case	Event	Time (sec.)
BOC HZP	Beginning of reactivity insertion	0.0
	Ejected CEA fully withdrawn	0.10
	VHPT setpoint reached	1.18
	Maximum nuclear power	1.42
	Reactor scram on VHPT (including trip response delay)	2.28
	CEA insertion begins	2.78
	Maximum core heat flux through cladding	4.3
	MDNBR	4.3
	Maximum fuel centerline temperature	5.4
EOC HZP	Beginning of reactivity insertion	0.0
	Ejected CEA fully withdrawn	0.10
	VHPT setpoint reached	1.44
	Maximum nuclear power	1.62
	Reactor scram on VHPT (including trip response delay)	2.54
	CEA insertion begins	3.04
	MDNBR	4.0
	Maximum core heat flux through cladding	4.1
	Maximum fuel centerline temperature	5.4
BOC HFP	Beginning of reactivity insertion	0.0
	VHPT setpoint reached	0.02
	Ejected CEA fully withdrawn	0.10
	Maximum nuclear power	0.14
	Reactor scram on VHPT (including trip response delay)	0.42
	CEA insertion begins	0.92
	Maximum core heat flux through cladding	2.0
	MDNBR	2.0
	Maximum fuel centerline temperature	3.3

Table 2.8.5.4.6-1 (Continued)
CEA Ejection
Sequence of Events – Fuel Response

Case	Event	Time (sec.)
EOC HFP	Beginning of reactivity insertion	0.0
	VHPT setpoint reached	0.05
	Ejected CEA fully withdrawn	0.10
	Maximum nuclear power	0.13
	Reactor scram on VHPT (including trip response delay)	0.45
	CEA insertion begins	0.95
	Maximum core heat flux through cladding	1.3
	MDNBR	1.3
	Maximum fuel centerline temperature	3.0

Table 2.8.5.4.6-2
CEA Ejection
HZP Results

Criterion	BOC HZP EPU Analysis	EOC HZP EPU Analysis	Limit
MDNBR (% fuel failure)	2.442 (0%)	2.917 (0%)	1.164
Fuel Centerline Temperature (% fuel failure)	4038°F (0%)	3212°F (0%)	4623°F
Deposited Enthalpy	21.2 cal/gm	29.1 cal/gm	280 cal/gm

Table 2.8.5.4.6-3
CEA Ejection
HFP Results and Comparison to Previous Results

Criterion	BOC HFP		EOC HFP		Limit
	Previous Analysis	EPU Analysis	Previous Analysis	EPU Analysis	
MDNBR (% fuel failure)	Not calculated	1.234 (0%)	Not calculated	1.984 (0%)	1.164
Fuel Centerline Temperature (%fuel failure)	Not calculated	4607°F (0%)	Not calculated	4385°F (0%)	4623°F
Deposited Enthalpy	177.8 cal/gm	166.4 cal/gm	177.9 cal/gm	155.9 cal/gm	280 cal/gm

Table 2.8.5.4.6-4
CEA Ejection
Sequence of Events – RCS Overpressure

Case	Event	Time (sec.)
BOC HFP	Beginning of reactivity insertion	0.0
	VHPT setpoint reached	0.02
	Ejected CEA fully withdrawn	0.10
	Maximum nuclear power	0.14
	Reactor scram on VHPT (including trip response delay)	0.42
	CEA insertion begins	0.92
	Maximum core heat flux through cladding	2.0
	Pressurizer Safety Valves open	3.3
	Maximum RCS pressure	3.5
	Pressurizer Safety Valves close	4.6

Figure 2.8.5.4.6-1
CEA Ejection
(BOC HFP)
Reactor Power

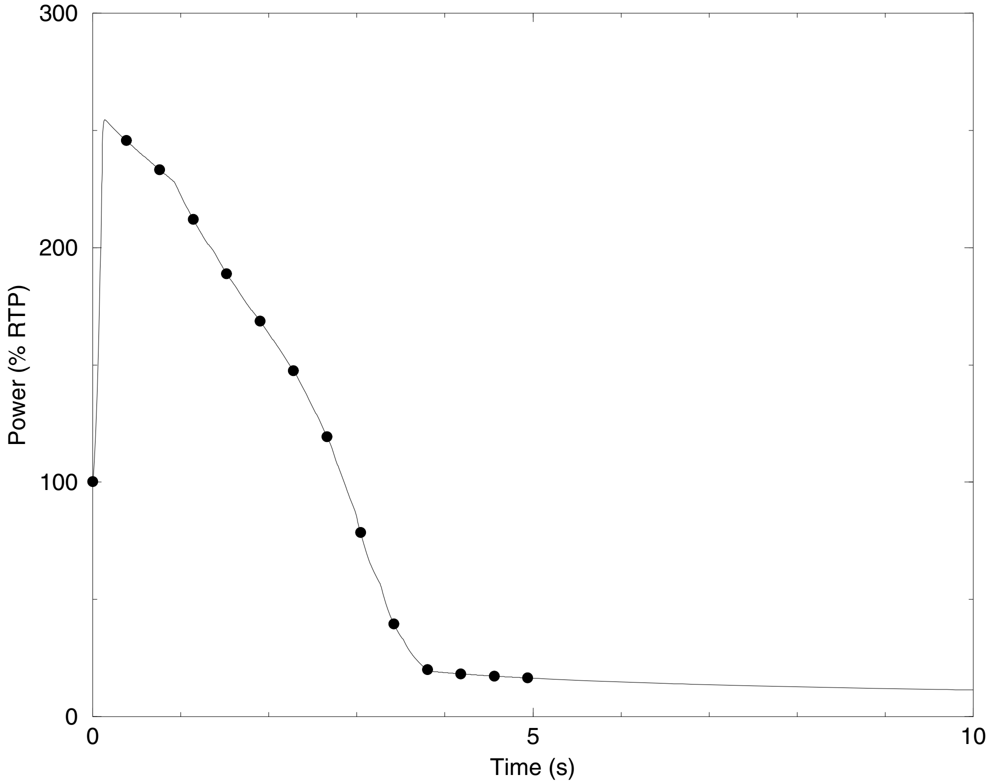


Figure 2.8.5.4.6-2
CEA Ejection
(BOC HFP)
Total Core Heat Flux Power

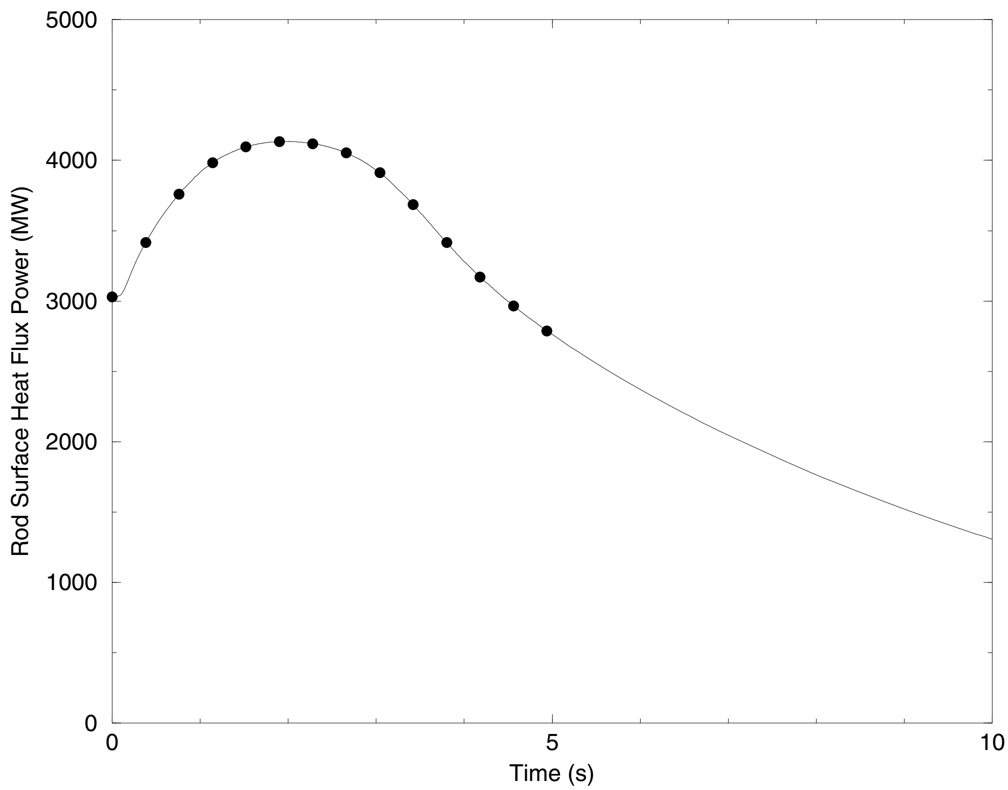


Figure 2.8.5.4.6-3
CEA Ejection
(BOC HFP)
RCS Loop Temperature

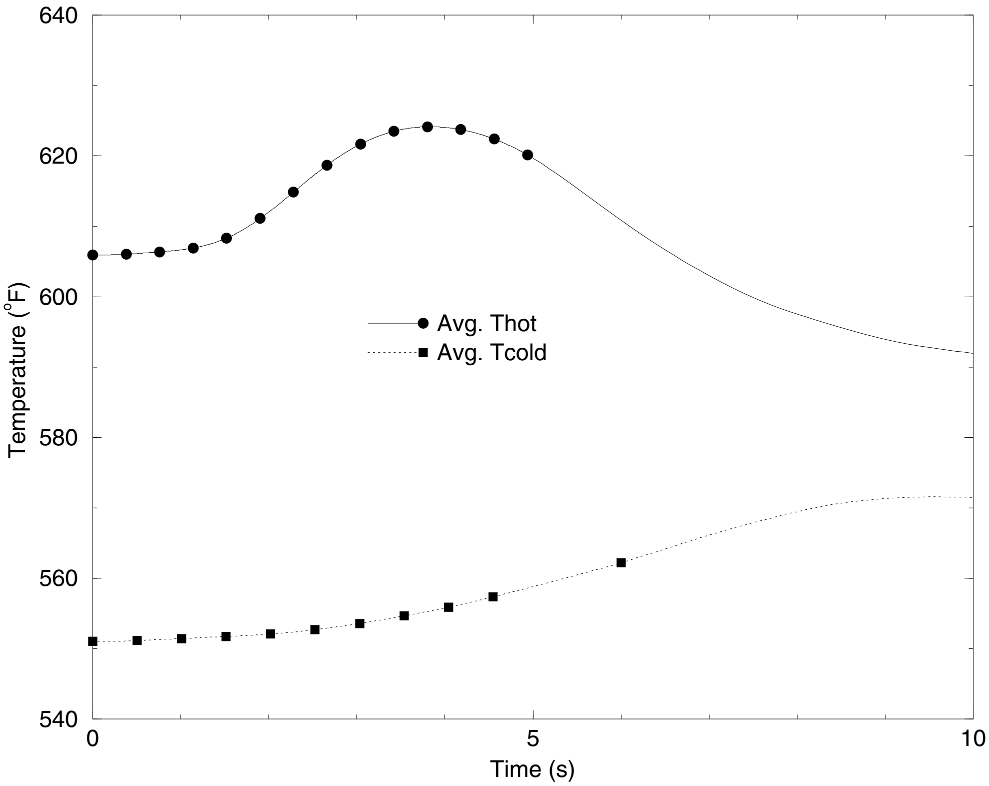


Figure 2.8.5.4.6-4
CEA Ejection
(BOC HFP)
RCS Total Loop Flow Rate

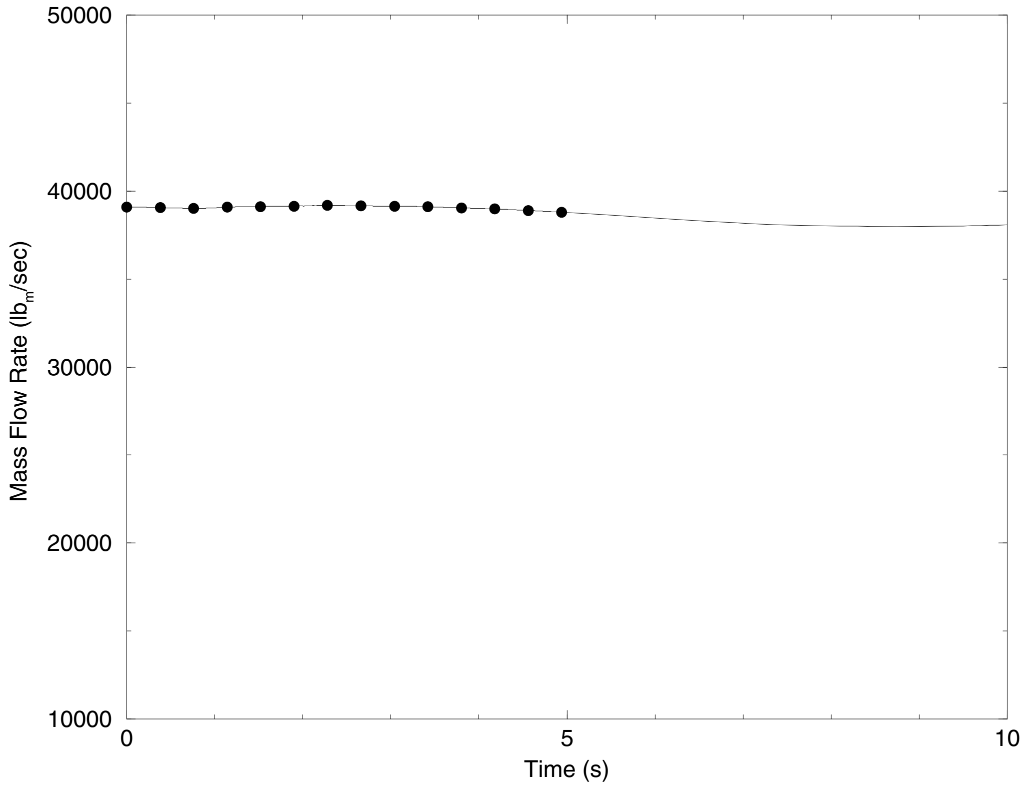


Figure 2.8.5.4.6-5
CEA Ejection
(BOC HFP)
Reactivity Feedback

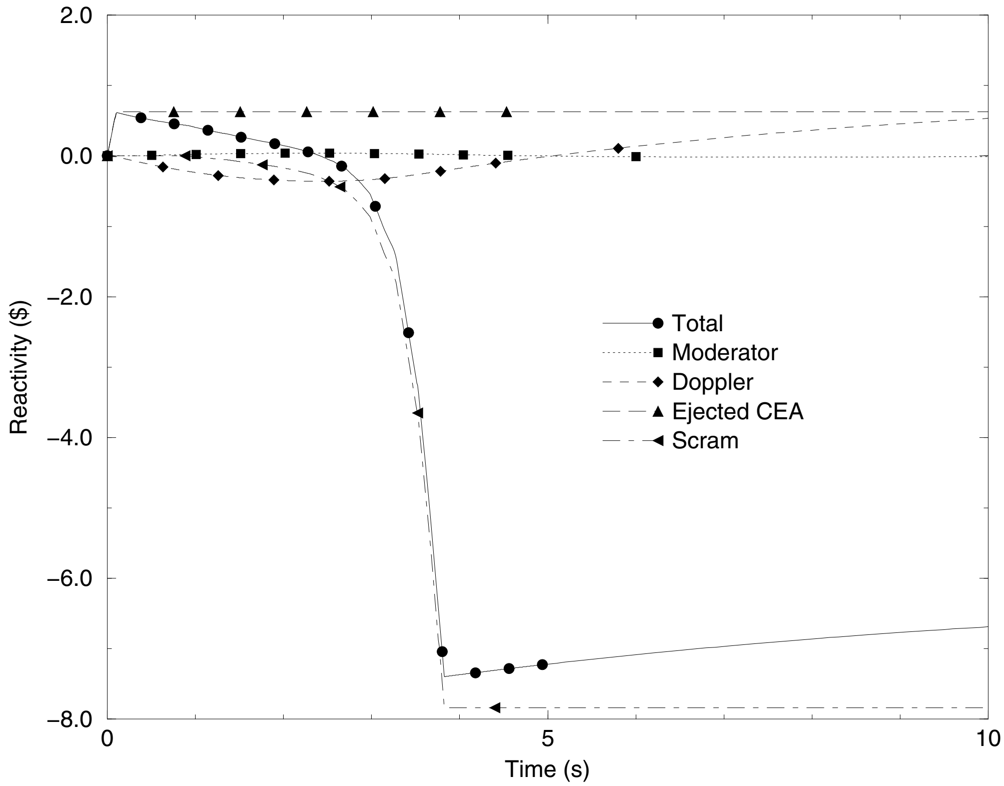


**Figure 2.8.5.4.6-6
CEA Ejection
(BOC HFP)
Peak Fuel Centerline Temperature**

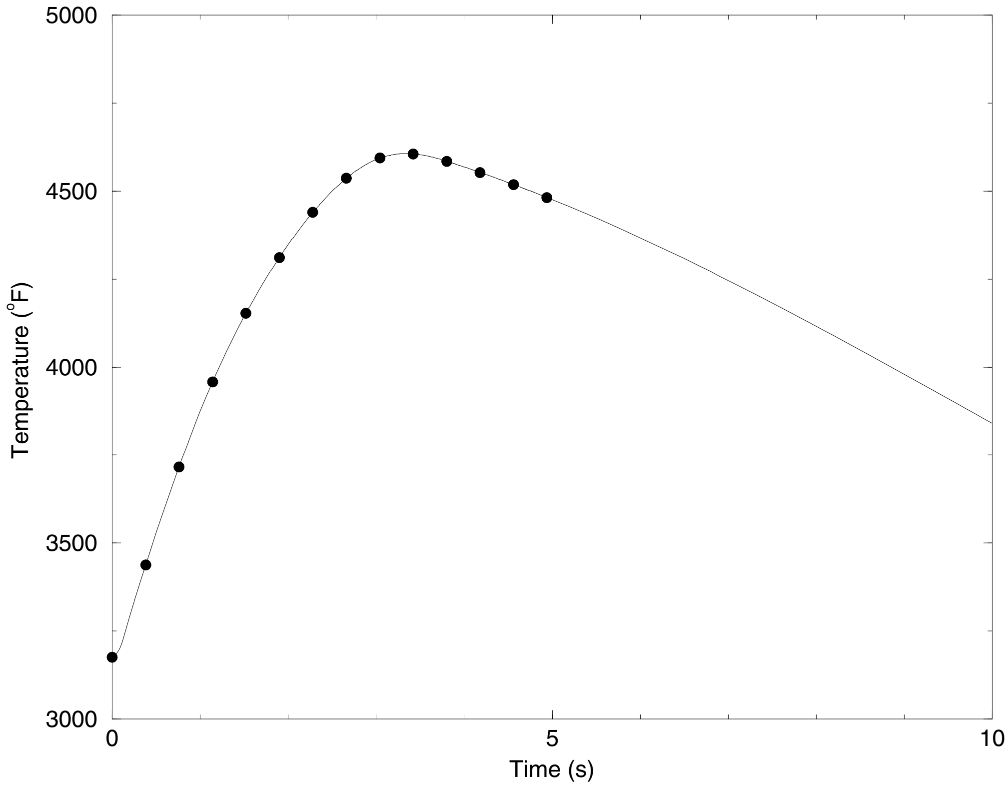
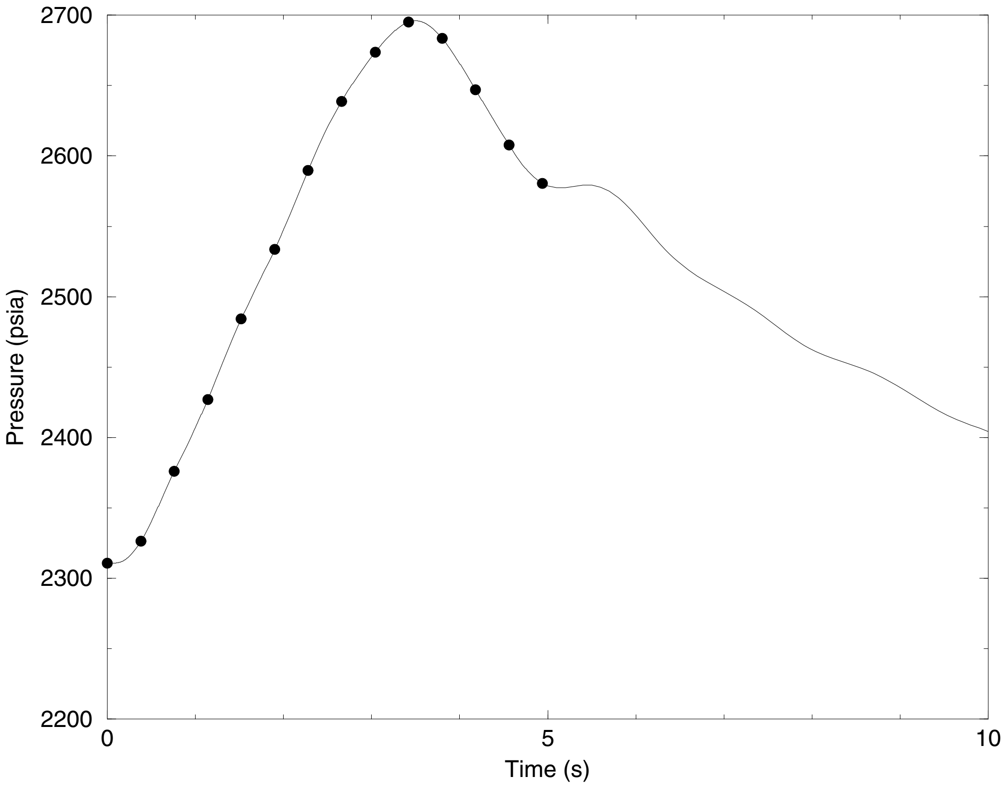


Figure 2.8.5.4.6-7
CEA Ejection
(BOC HFP)
Peak RCS Pressure



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

Florida Power & Light's (FPL) review of the inadvertent operation of emergency core cooling system (ECCS) and chemical and volume control system (CVCS) malfunction event that increases reactor coolant inventory has determined that this event is not in the St. Lucie Unit 1 current licensing basis (CLB).

The high head safety injection pumps are not capable of injecting water into the reactor coolant system at normal operating pressure. Therefore, inadvertent operation of ECCS that increases reactor coolant inventory is not credible and is not included in the St. Lucie Unit 1 CLB.

A CVCS malfunction event that increases reactor coolant inventory has not been analyzed and is also not in the St. Lucie Unit 1 CLB. The CVCS malfunction as a boron dilution event is included in the CLB as described in UFSAR Section 15.2.4 and is evaluated for the extended power uprate 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.

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.

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 for this review are based on:

- 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 margin sufficient to ensure 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 15.6.1 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC applicable to the inadvertent opening of a pressurizer pressure relief valve 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.

The ANSI-N 18.2 design requirement for normal operation 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 AOOs is that such occurrences 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 an adequate protective system. Refer to UFSAR Section 7.2 and Chapter 15.

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the Technical Specifications (TS) (Limiting Safety System Settings and 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 operations including anticipated operational occurrences.

The operating conditions established for the normal steady-state and transient operation and AOOs are discussed in UFSAR Chapter 5. The control systems are designed to maintain the controlled plant variables within these operating limits, thereby ensuring that a satisfactory margin is maintained between the plant operating conditions and the design limits.

The reactor protection system (RPS) (UFSAR Section 7.2) functions to minimize the deviation from normal operating limits in the event of certain AOOs; the results of analyses given in UFSAR Sections 15.2 and 15.3 show that the design limits of the RCPB are not exceeded in the event of any AOOs.

- 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 controlling reactivity changes to assure that under conditions of normal operation, including AOOs; SAFDLs are not exceeded. Refer to UFSAR Section 4.2.3. 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. Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition. The soluble boron system is capable of holding, the reactor subcritical under cold conditions. Refer to UFSAR Section 9.3.4 for details.

Discussion of the inadvertent opening of the pressurizer pressure relief valve event is provided in UFSAR Section 15.2.12.

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 inadvertent opening of pressurizer pressure relief valve, or RCS depressurization, event is defined as an accidental opening of the pressurizer power operated relief valves (PORV) due to a mechanical failure, a spurious actuation signal, or unanticipated operator action. The two PORVs are designed to relieve sufficient pressurizer steam during operational transients and most of the anticipated transients to prevent opening of the pressurizer safety valves. Inadvertent opening of the pressurizer PORVs results in a rapid depressurization of the RCS and a challenge to the departure from nucleate boiling (DNB) SAFDL. The core is protected from reaching the DNB SAFDL by the thermal margin/low pressure (TM/LP) trip.

Since the systems designed to mitigate this event in the short term (namely, the RPS) are redundant, there is no single active failure that will adversely affect the consequences of the event.

2.8.5.6.1.2.2 Input Parameters, Assumptions and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 2 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions - This event was assumed to initiate from hot full power (HFP) conditions with a maximum core inlet temperature and TS minimum RCS flow. This set of conditions minimizes the initial margin to DNB.

- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. Beginning of cycle (BOC) moderator density feedback was conservatively assumed for this event, although the reactivity feedback is not a significant parameter.
- Reactor Protection System Trips and Delays - This event is primarily protected by the TM/LP RPS trip. The RPS trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, rod insertion was delayed to account for CEA holding coil delay time.
- Pressurizer PORV Flow Rate – A conservative pressurizer PORV flow rate was assumed for this analysis. The value was based on two valves opening and the flow rate was biased 20% higher to maximize the depressurization of the RCS and the potential pressure undershoot of the RPS trip setpoint.
- Gap Conductance – Gap conductance was set to a conservative BOC value to be consistent with the time-in-cycle for the reactivity coefficients.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses, provides the SGTP level supported by the analyses.

Consistent with the current licensing basis, the principally challenged acceptance criterion for this event is:

- Fuel cladding integrity should be maintained by ensuring that the SAFDLs are not exceeded.

This criterion is met by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the 95/95 DNB correlation limit. Since this event does not involve a significant power transient or augmented peaking, the fuel centerline melt limit is not challenged. Also, this event results in the RCS depressurization and thus, does not challenge the RCPB.

2.8.5.6.1.2.3 Description of Analyses and Evaluations

Analyses supporting current plant operation were performed with the non-LOCA methodologies based on the PTSPWR2 code (Reference 1). For the EPU, detailed analyses were performed with the approved non-LOCA methodology given in Reference 2. For this event, the S-RELAP5 code was used to model the key system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures), and an estimated time of minimum departure from nucleate boiling ratio (MDNBR). The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code (Reference 3), which was used to calculate the MDNBR using the higher thermal performance (HTP) critical heat flux (CHF) correlation (Reference 4). This event was also addressed as part of the TM/LP statistical setpoint analyses (LR Section 2.8.5.0, Accident and Transient Analyses) using the Reference 5 methodology.

A single calculation was performed at BOC HFP conditions, maximum TS core inlet temperature, and minimum TS RCS flow rate. This produced the minimum margin to the DNB limit. A conservative moderator density reactivity feedback was used, based on the hot zero power (HZP) TS/ core operating limits report (COLR) moderator temperature coefficient (MTC). The analysis simulates an inadvertent and instantaneous full opening of both pressurizer PORVs which maximizes the depressurization of the RCS and challenge to the DNB SAFDL.

2.8.5.6.1.2.4 Evaluation of 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 sequence of events is shown in LR Table 2.8.5.6.1-1. Results are given in LR Table 2.8.5.6.1-2. The limiting MDNBR was calculated to be above the 95/95 limit for the HTP CHF correlation.

The system responses are shown in LR Figures 2.8.5.6.1-1 through 2.8.5.6.1-7. LR Figure 2.8.5.6.1-1 shows the reactor power as a function of time. LR Figure 2.8.5.6.1-2 shows the core power based on rod surface heat flux. LR Figures 2.8.5.6.1-3 through 2.8.5.6.1-7 show the pressurizer pressure, the PORV flow rate, the RCS loop temperatures, the total RCS flow rate, and the reactivity feedback, respectively.

For the DNB portion of the event, the pressurizer does not fill with liquid water during this event as shown in LR Figure 2.8.5.6.1-8. 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.

2.8.5.6.1.3 Conclusion

FPL has reviewed the analysis of the inadvertent opening of a pressure relief valve event and concludes 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 analysis 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 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 extended power uprate (EPU). Therefore, FPL finds the proposed EPU acceptable with respect to the inadvertent opening of a pressure relief valve event.

2.8.5.6.1.4 References

1. ANF-84-73(P)(A), Revision 5, Appendix B, & Supplements 1 and 2, Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events, Advanced Nuclear Fuels Corporation, October 1990.

2. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

3. XN-NF-82-21(P)(A), Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. EMF-92-153(P)(A), Revision 1, HTP: Departure From Nucleate Boiling Correlation for High Thermal Performance Fuel, Siemens Power Corporation, January 2005.

5. EMF-1961(P)(A), Revision 0, Statistical/Transient Methodology for Combustion Engineering Type Reactors, Siemens Power Corporation, July 2000.

Table 2.8.5.6.1-1
Inadvertent Opening of Pressurizer PORV
Sequence of Events

Event	Time (sec.)
PORVs fail open	0.0
TM/LP trip reached	38.3
Reactor scram on TM/LP (including trip response delay)	39.2
MDNBR	39.6
CEA insertion begins	39.7

Table 2.8.5.6.1-2
Inadvertent Opening of Pressurizer PORV
Results and Comparison to Previous Results

Criterion	Previous Analysis	EPU Analysis	Limit
MDNBR	1.389	1.350	1.164

Figure 2.8.5.6.1-1
RCS Depressurization
Reactor Power

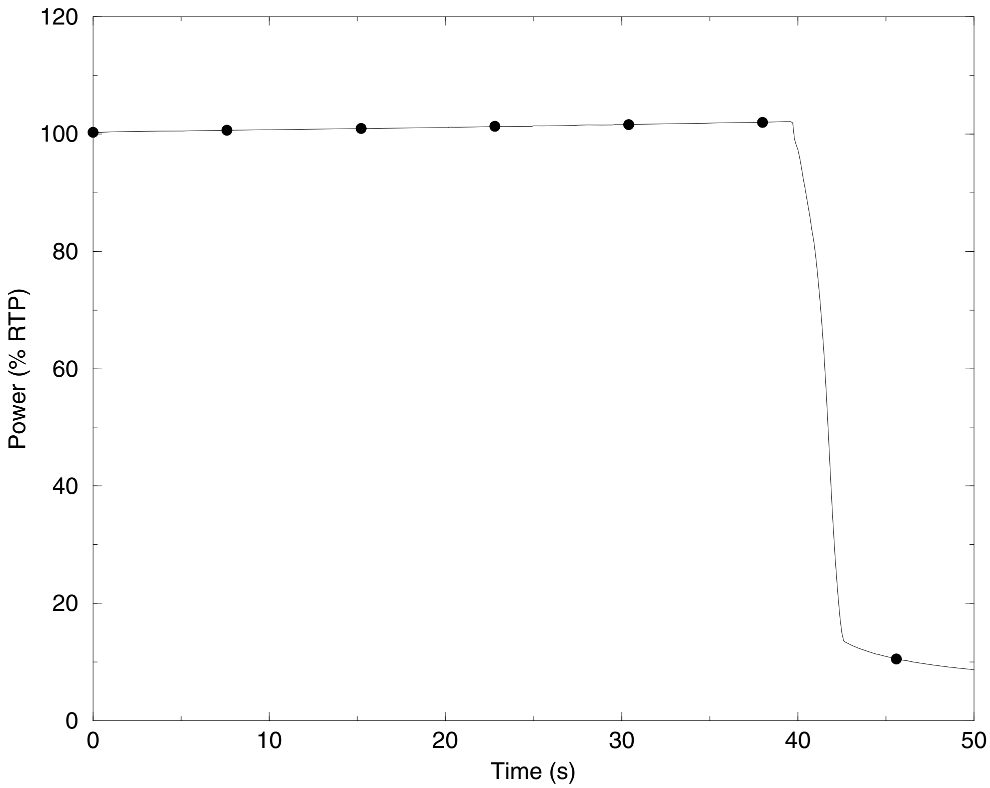


Figure 2.8.5.6.1-2
RCS Depressurization
Total Core Heat Flux Power

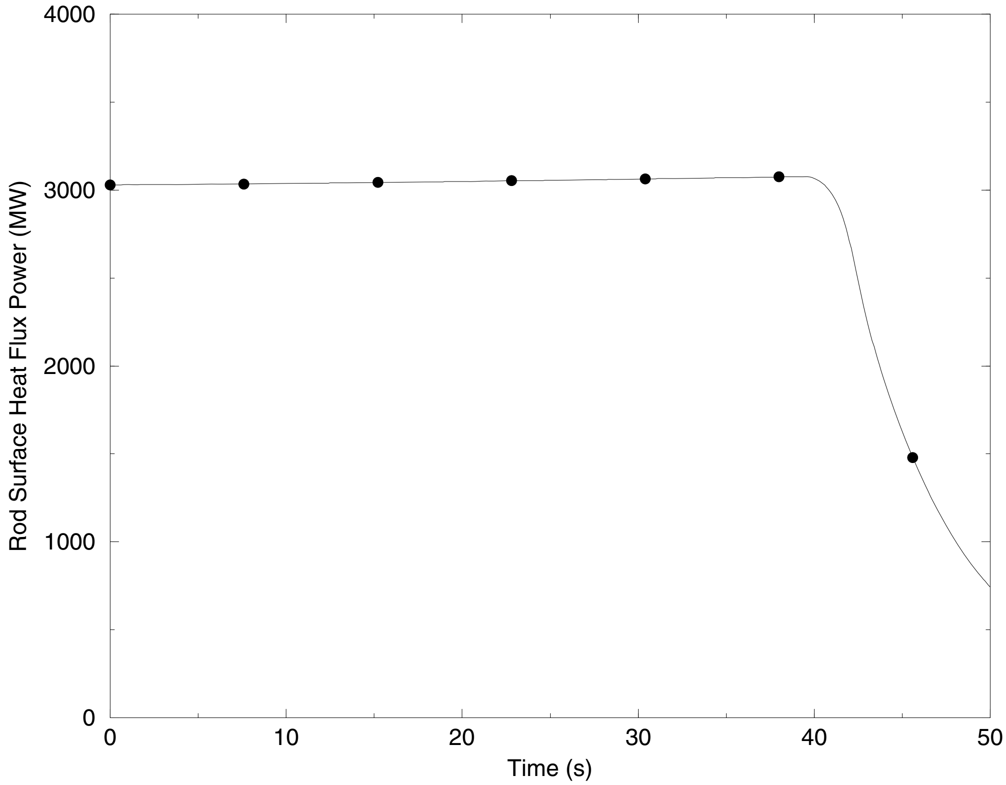


Figure 2.8.5.6.1-3
RCS Depressurization
Pressurizer Pressure

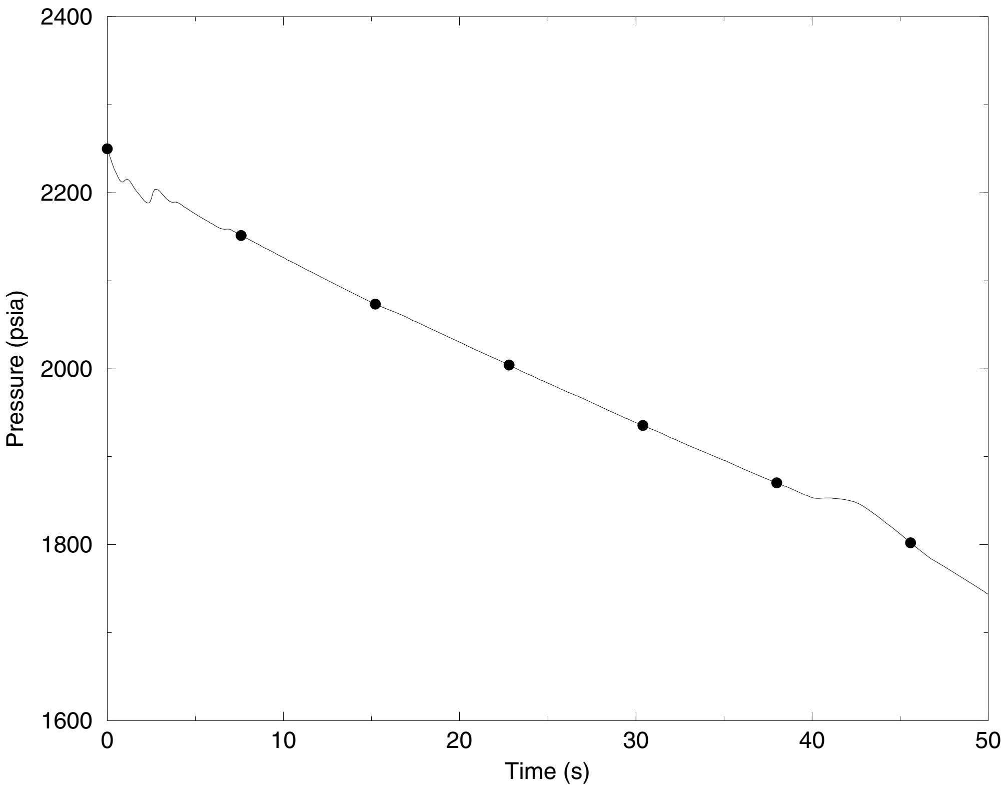


Figure 2.8.5.6.1-4
RCS Depressurization
Pressurizer PORV Flow Rate

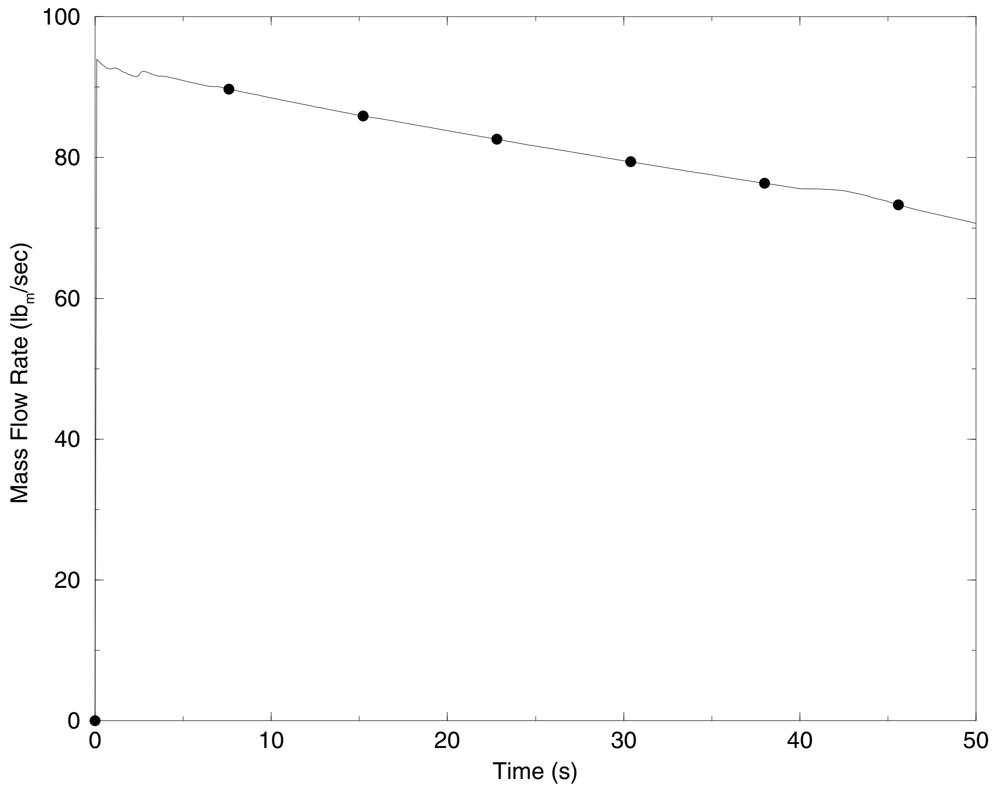


Figure 2.8.5.6.1-5
RCS Depressurization
RCS Loop Temperatures

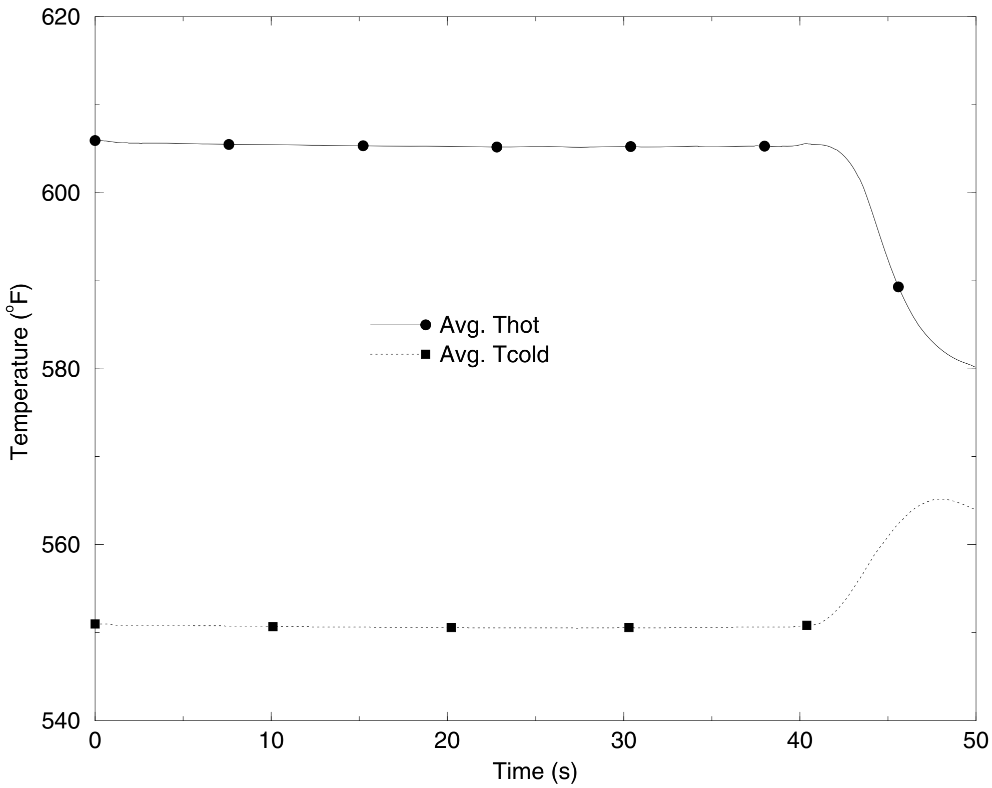


Figure 2.8.5.6.1-6
RCS Depressurization
RCS Total Loop Flow Rate

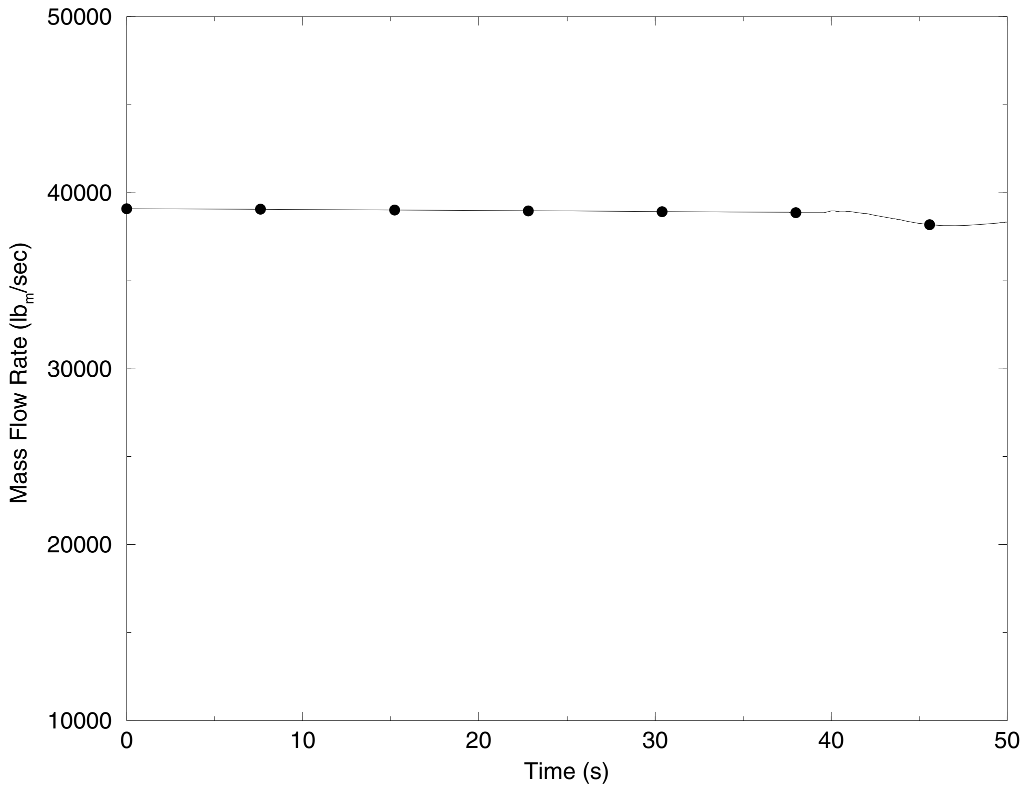


Figure 2.8.5.6.1-7
RCS Depressurization
Reactivity Feedback

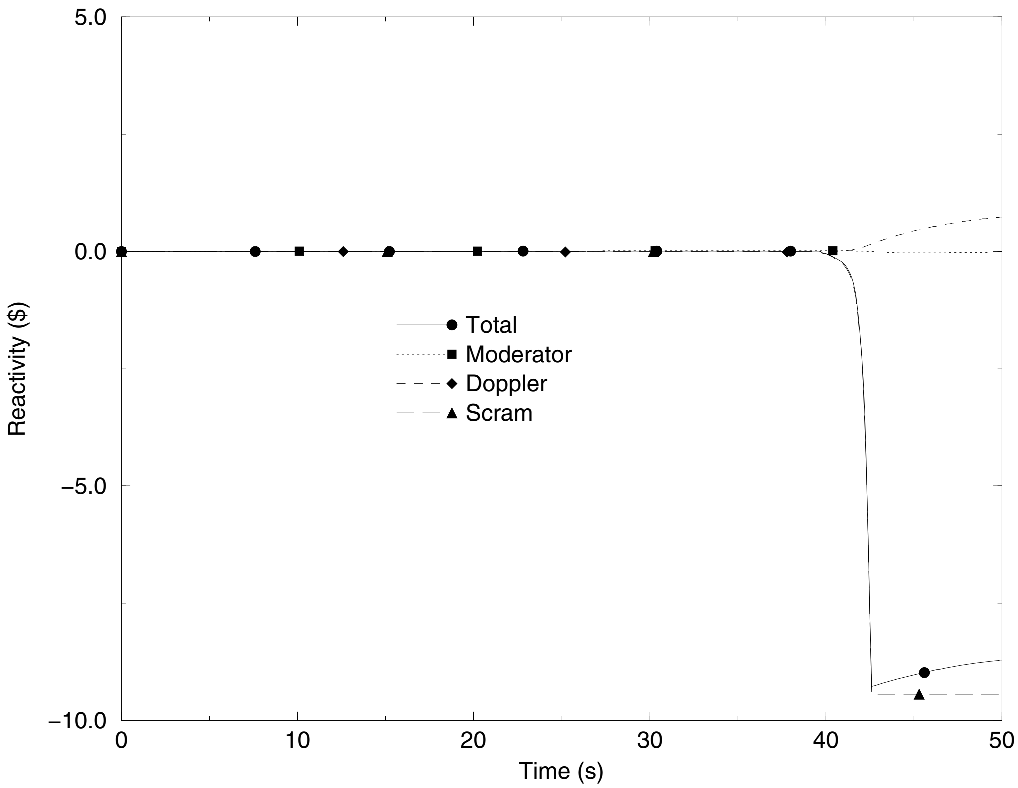
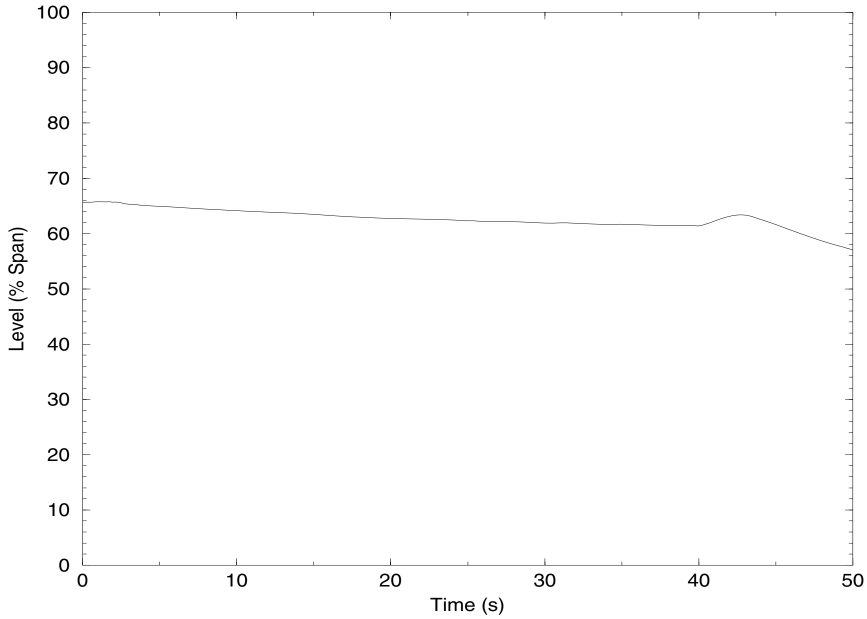


Figure 2.8.5.6.1-8
Pressurizer Level vs. Time



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 the main condenser, the main steam safety valves (MSSVs) or the atmospheric relief valves, referred to at St. Lucie Unit 1 as atmospheric dump valves (ADVs). Reactor protection and engineered safety features (ESFs) are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR 50.67.

FPL's review covered:

- Postulated initial core and plant conditions,
- Method of thermal and hydraulic analysis,
- 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 accident analysis.

FPL's review focused on the thermal and hydraulic analyses 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 Terms (AST).
- 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 RS-001.

St. Lucie Unit 1 Current Licensing Basis

Discussion of the SGTR event is provided in UFSAR Section 15.4.4.

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.

2.8.5.6.2.2 Technical Evaluation

2.8.5.6.2.2.1 Introduction

A SGTR event results in a penetration of the barrier between the reactor coolant system (RCS) and the main steam system. The event is postulated to be a double-ended rupture of one SG tube at full power. The event is characterized by a depressurization of the RCS with reactor trip on a thermal margin/low pressure (TM/LP) signal. Loss of offsite power occurs at reactor trip after which the steam bypass control system (SBCS) is not credited and steam release is via the SG MSSVs. Operators isolate the affected SG by closing the main steam isolation valves (MSIVs) and begin cooldown using the ADV on the unaffected SG.

2.8.5.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The key input parameters and their values used in the analysis of this event are consistent with the approved Reference 1 methodology. See LR Section 2.8.5.0, Accident and Transient Analyses, for the input parameter values.

- Initial Conditions – This event was analyzed from hot full power (HFP) to produce the highest decay heat level and the most significant atmospheric steam release.
- Reactivity Feedback – The reactivity feedback coefficients were biased according to the approved methodology. Beginning of cycle (BOC) moderator density feedback was assumed for this event, although the reactivity feedback is not a significant parameter.
- Reactor Protection System (RPS) Trips and Delays – This event is primarily protected by the TM/LP RPS trip. Appropriate uncertainties and delay times were used.
- Decay Heat – Decay heat was calculated using the 1973 ANS standard plus actinides in accordance with the approved methodology.
- Break Location and Characteristics – Two potential break locations were analyzed. The first location assumed the break occurred on the upside of the SG tube bundle above the tubesheet (i.e., hot-side break). The second location assumed the break occurred on the downside of the SG tube bundle above the tubesheet (i.e., cold-side break). A double-ended break of a single SG tube was modeled, such that RCS liquid was lost from both the upstream and downstream sides of the break. Moody critical flow was assumed at the rupture tube break junction.
- Offsite Power – Offsite power was assumed to be lost at reactor trip. The loss of offsite power results in the loss of the SBCS for removal of decay heat. Heat removal from the RCS is achieved by action of the SG MSSVs up to the time of operator action, at which time the ADV in the unaffected SG was credited.
- Operator Actions – An operator action time of up to 45 minutes was analyzed. Operators were assumed to isolate the affected SG by closing the MSIVs and begin cooldown using the ADV on the unaffected SG. This represents an increase from the operator action time of 30 minutes currently assumed in the analysis.
- Steam Generator Tube Plugging (SGTP) – LR Section 2.8.5.0, Accident and Transient Analyses provides the SGTP level supported by the analyses.

The principally challenged acceptance criterion for this event is with respect to radiological consequences. The analysis documented herein does not address radiological consequences directly; rather, the steam releases for input to the radiological analyses were calculated to support a plant cooldown to 212°F. This event is protected by the TM/LP trip and does not represent a significant challenge to the specified acceptable fuel design limits (SAFDLs).

2.8.5.6.2.2.3 Description of Analyses and Evaluations

The purpose of this analysis was to conservatively calculate the steam releases to the atmosphere for input to the radiological dose analyses. The limiting case presented here assumes no AFW to the affected steam generator which results in reduced liquid mass in the affected steam generator. This assumption conservatively overpredicts the concentration of activity in the affected steam generator due to less dilution of the RCS activity coming from the break flow. The dose consequences are thus maximized. Detailed analyses were performed with the approved methodology using the S-RELAP5 code (Reference 1). The S-RELAP5 code was used to model the key primary and secondary system components, RPS and ESF actuation trips and core kinetics. Pressurizer heaters were turned on to maximize the RCS pressure and the break flow. S-RELAP5 was used to calculate the steam releases from event initiation to the operator action time. While this analysis was not biased for SG overfill, the analysis showed sufficient margin to SG overfill to the time of operator action. A heat balance calculation was performed to determine the steam releases resulting from the cooldown of the plant to an RCS temperature of 212°F considering energy contributions from decay heat, heat structures and the fluid within the primary and secondary systems.

2.8.5.6.2.2.4 Evaluation of 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 sequence of events is shown in LR Table 2.8.5.6.2-1. The transient responses are shown in LR Figures 2.8.5.6.2-1 through 2.8.5.6.2-11 for the hot-side break. LR Figure 2.8.5.6.2-1 shows the reactor power as a function of time. LR Figures 2.8.5.6.2-2 through 2.8.5.6.2-11 shows the pressurizer pressure, the pressurizer liquid level, the RCS loop temperatures, the total RCS loop flow rate, the SG pressures, the reactivity feedback, the SG masses, the MSSV flow rate, the total break flow rate, and the integrated flow rate, respectively.

The radiological dose analyses are documented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

2.8.5.6.2.3 Conclusion

FPL has reviewed the analysis of the SGTR accident and concludes that the analysis have 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 with respect to the dose consequence, which are shown to meet the acceptance limits in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST) and that the event does not result in an overfill of the faulted SG. Therefore, FPL finds the proposed EPU acceptable with respect to the SGTR event.

2.8.5.6.2.4 References

1. EMF-2310(P)(A), Revision 1, SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., May 2004.

Table 2.8.5.6.2-1
Steam Generator Tube Rupture
(45 minute Operator Action Time)
Sequence of Events

Event	Hot Side Break Time (sec.)	Cold Side Break Time (sec.)
Reactor operating at HFP conditions	0.0	0.0
Double-ended rupture of a single SG tube occurred above tubesheet (0.002376 ft^2)	0.0	0.0
TM/LP trip setpoint reached	472.7	387.1
Turbine tripped on reactor trip – offsite power is assumed lost	473.6	388.0
Reactor coolant pumps (RCPs) lose power source and coastdown	473.6	388.0
MFW lost due to LOOP	473.6	388.0
Control element assembly (CEA) insertion begins	474.1	388.5
CEAs fully inserted	477.5	391.9
SG narrow range level reached 0.0%	520	400
Auxiliary feedwater flow began	520	400
Charging flow began	640	580
High pressure safety injection flow began	1180	1000
Operator initiated controlled cooldown • MSIV on affected SG was closed • ADV on unaffected SG used for cooling the plant	2700	2700

Figure 2.8.5.6.2-1
Steam Generator Tube Rupture
(Hot Side Break)
Reactor Power

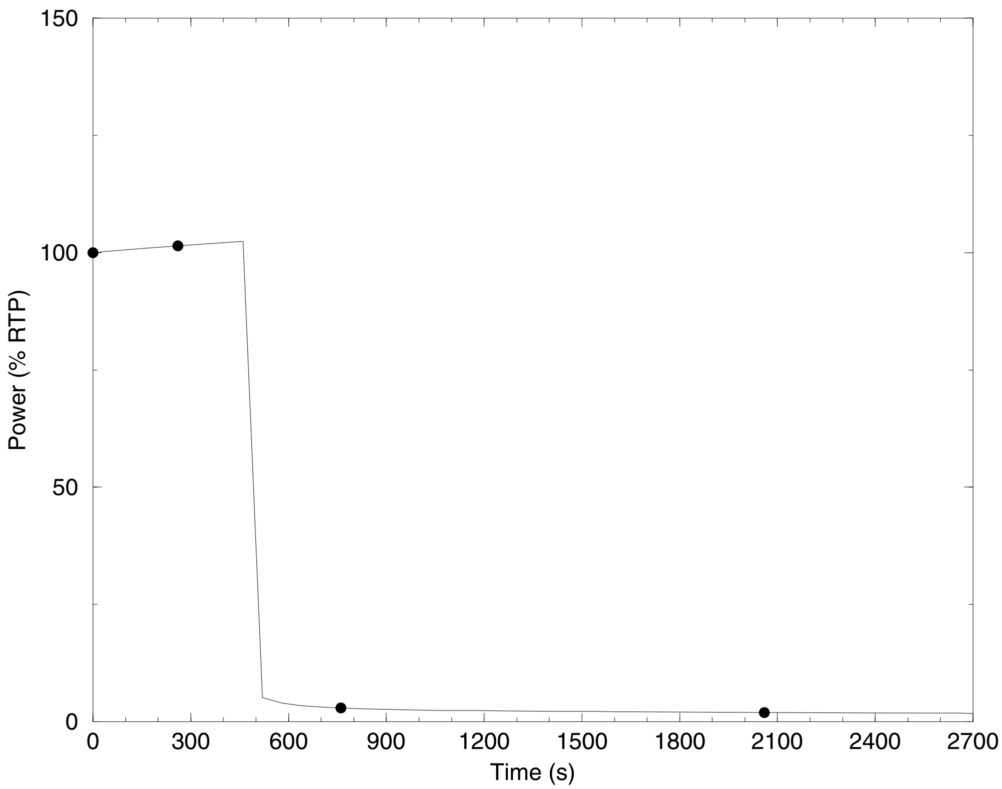


Figure 2.8.5.6.2-2
Steam Generator Tube Rupture
(Hot Side Break)
Pressurizer Pressure

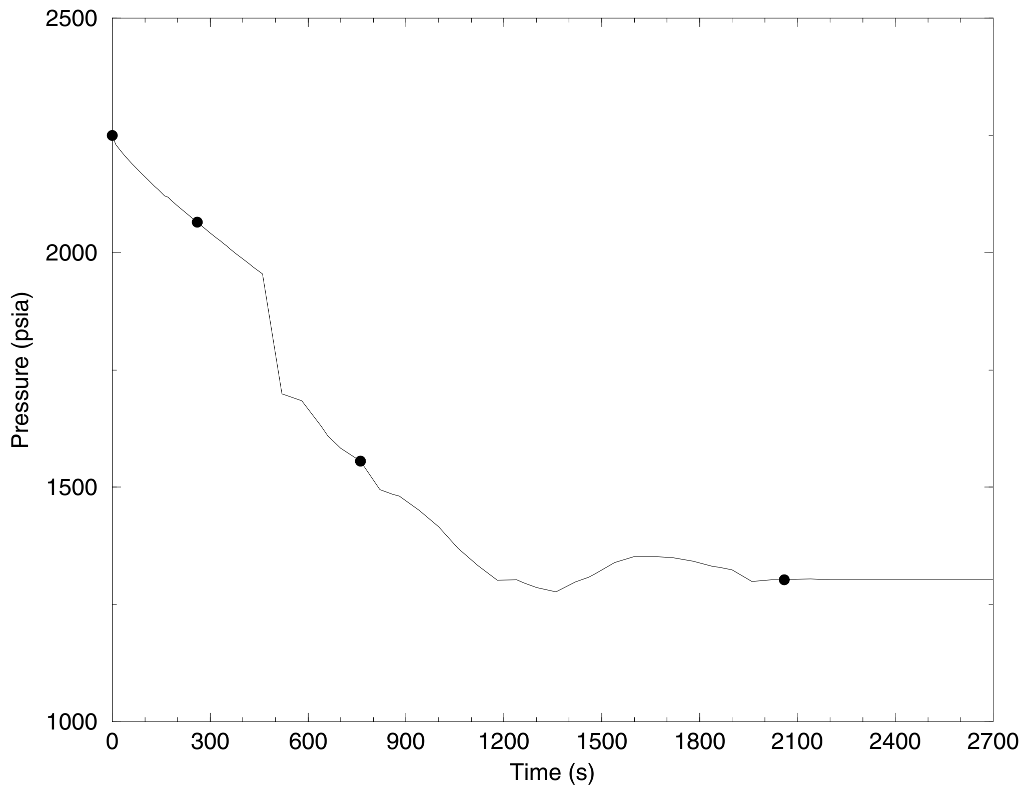


Figure 2.8.5.6.2-3
Steam Generator Tube Rupture
(Hot Side Break)
Pressurizer Liquid Level

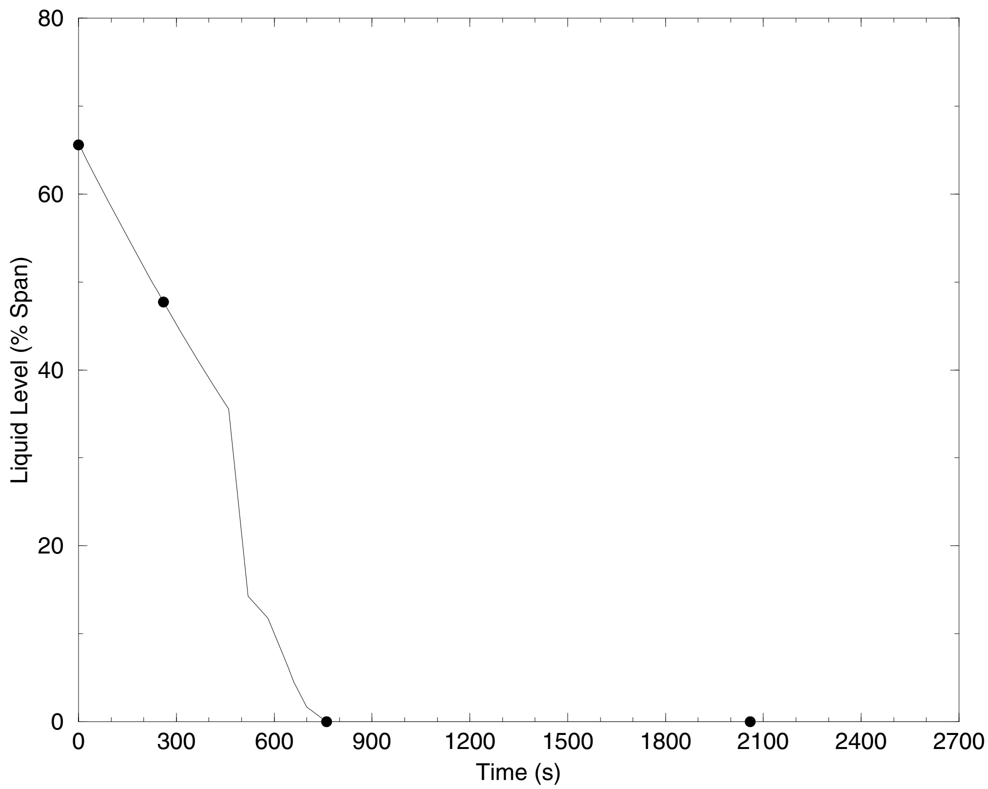


Figure 2.8.5.6.2-4
Steam Generator Tube Rupture
(Hot Side Break)
RCS Loop Temperatures

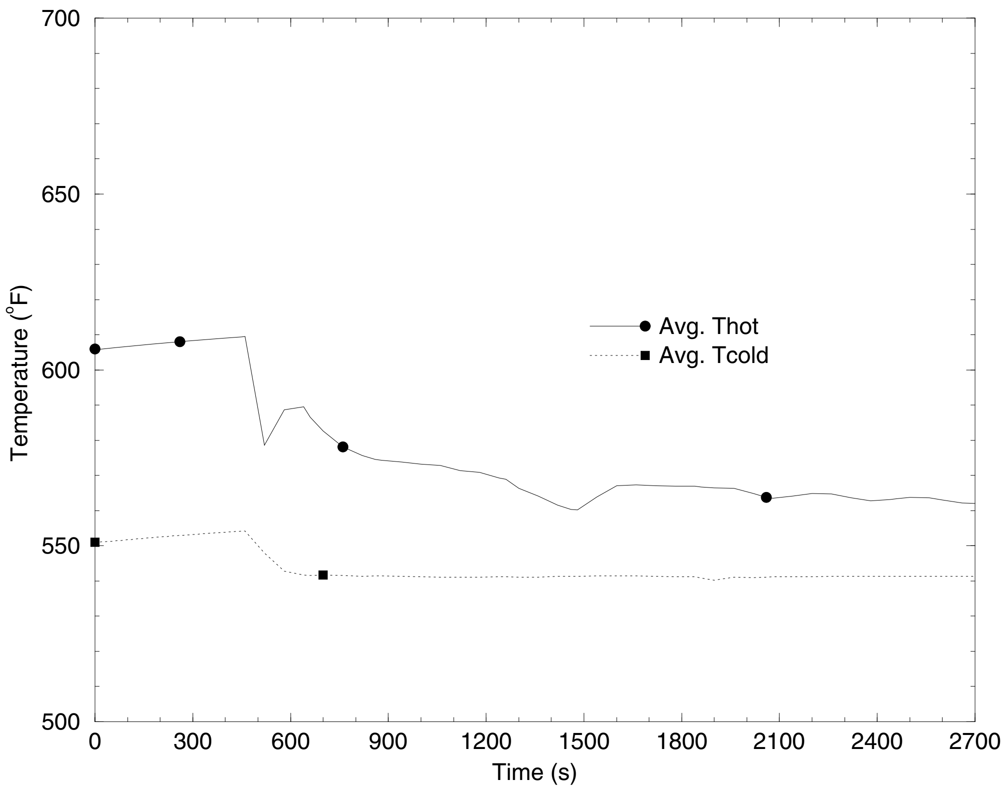


Figure 2.8.5.6.2-5
Steam Generator Tube Rupture
(Hot Side Break)
RCS Total Loop Flow Rate

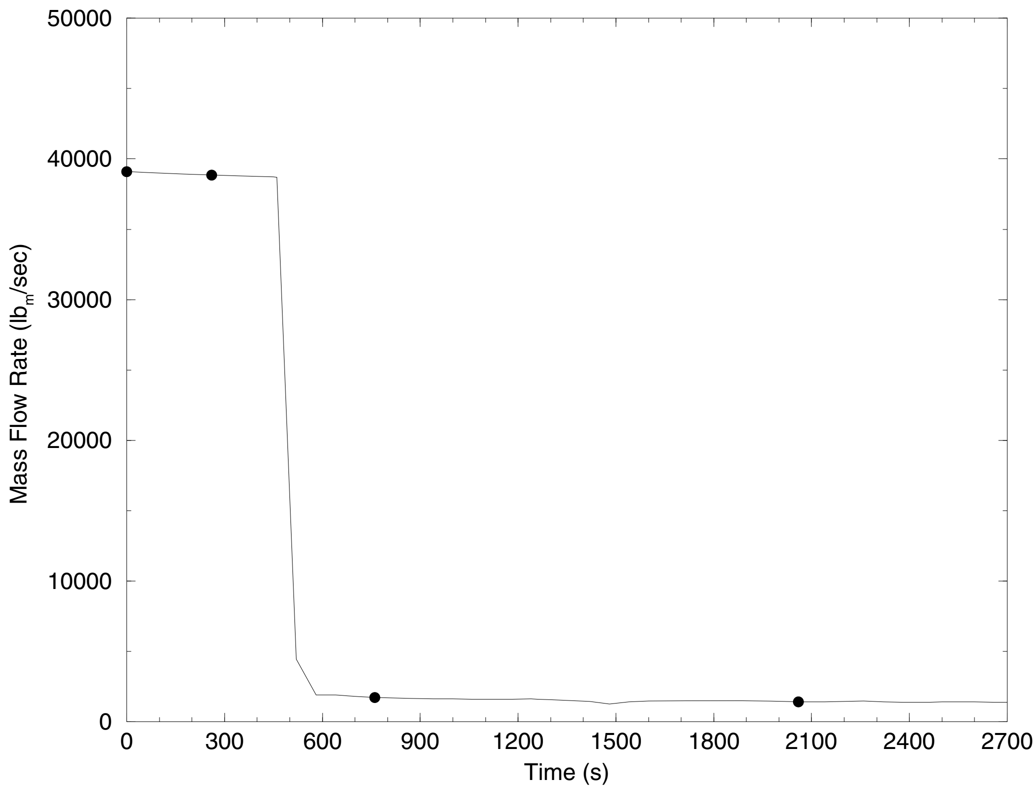


Figure 2.8.5.6.2-6
Steam Generator Tube Rupture
(Hot Side Break)
Steam Generator Pressures

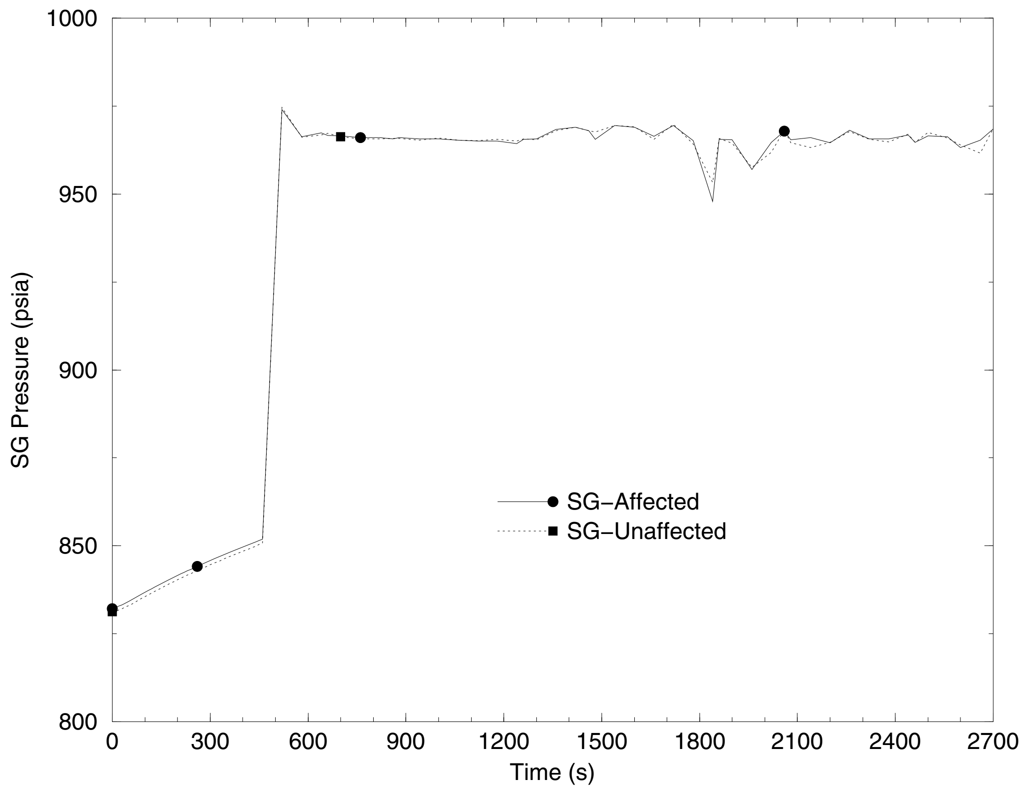


Figure 2.8.5.6.2-7
Steam Generator Tube Rupture
(Hot Side Break)
Reactivity Feedback

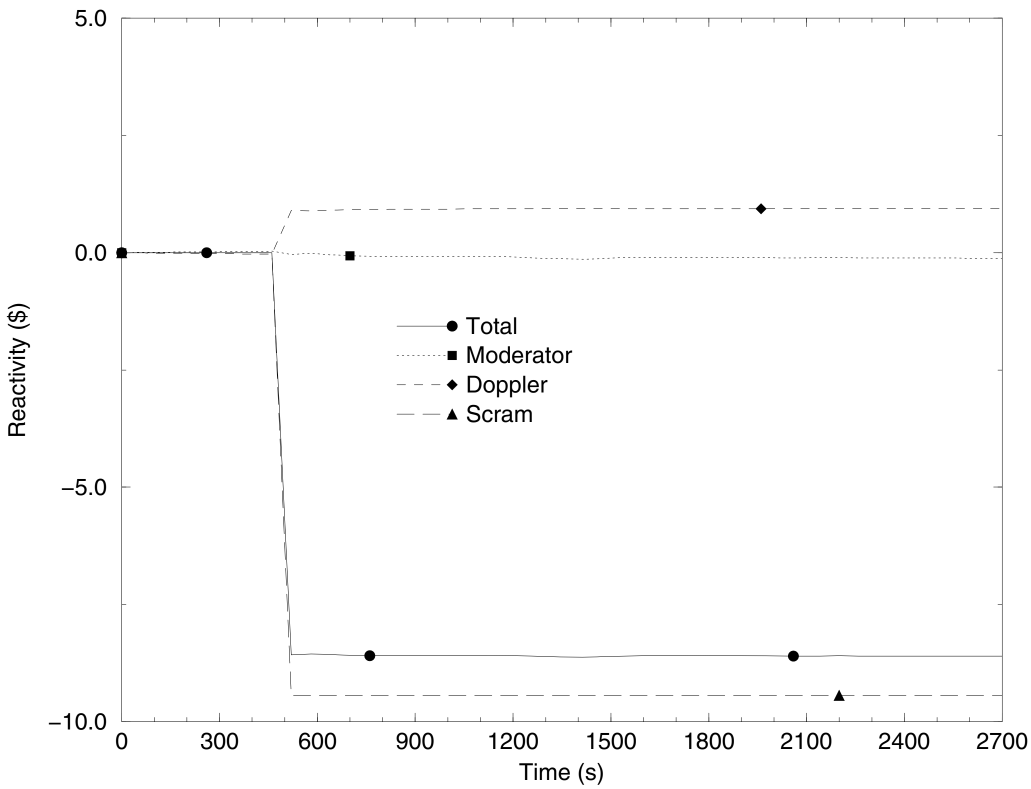


Figure 2.8.5.6.2-8
Steam Generator Tube Rupture
(Hot Side Break)
Steam Generator Masses

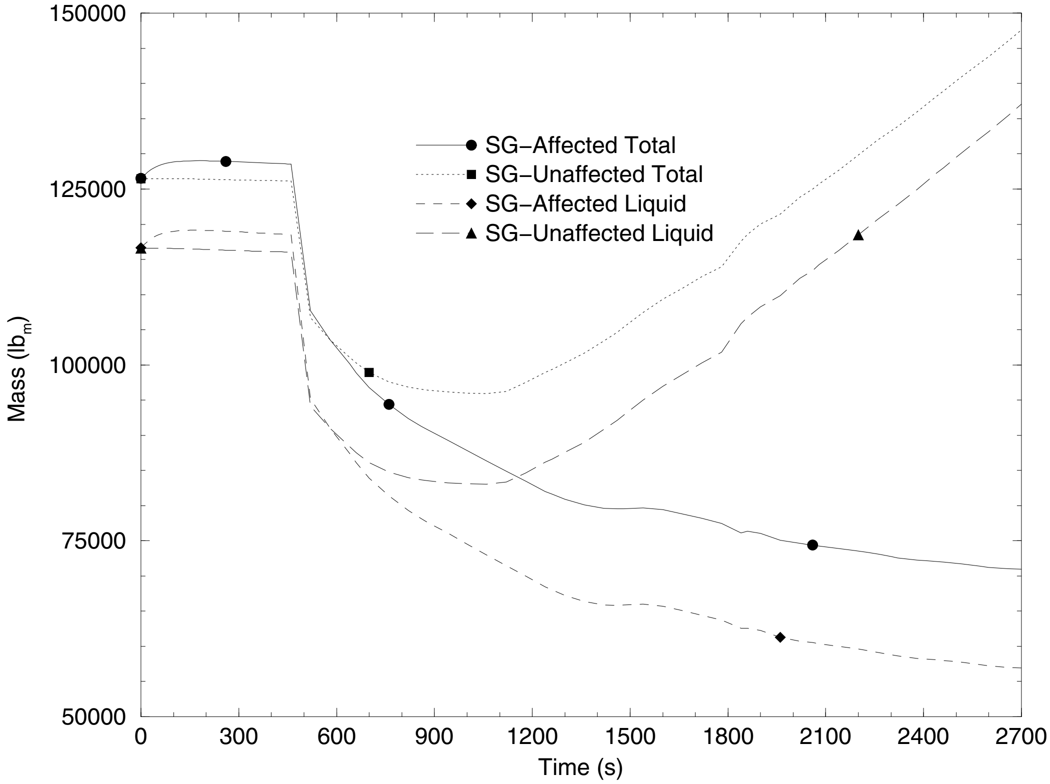


Figure 2.8.5.6.2-9
Steam Generator Tube Rupture
(Hot Side Break)
MSSV Flow Rate

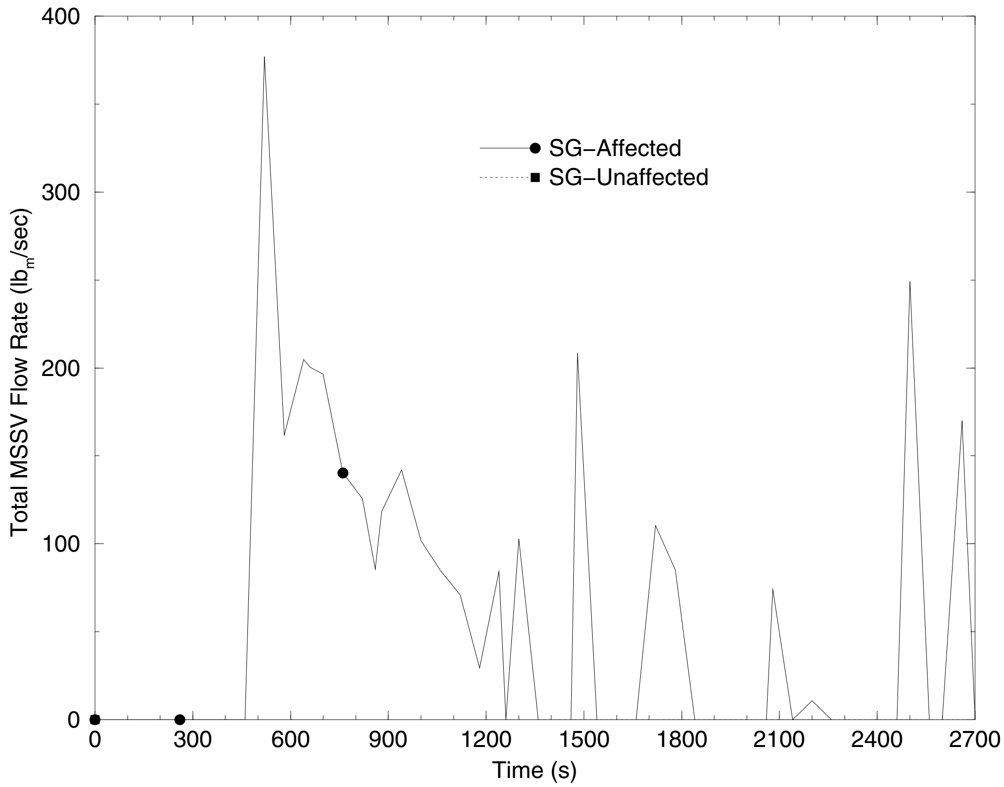


Figure 2.8.5.6.2-10
Steam Generator Tube Rupture
(Hot Side Break)
Total Break Flow Rate

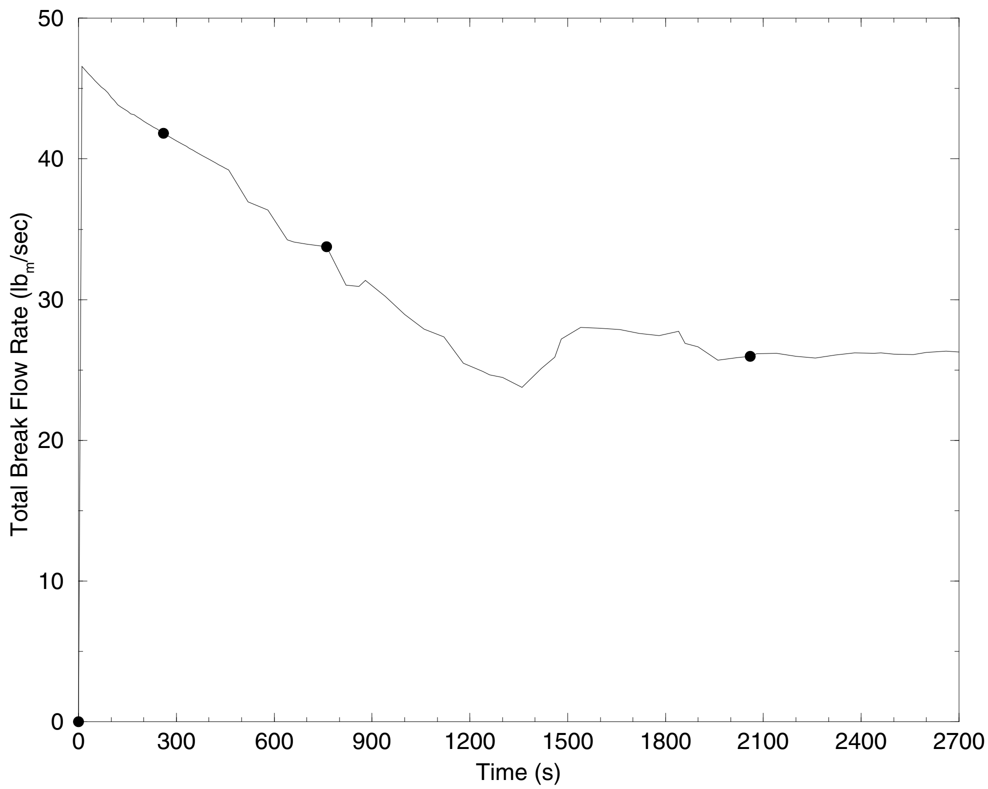
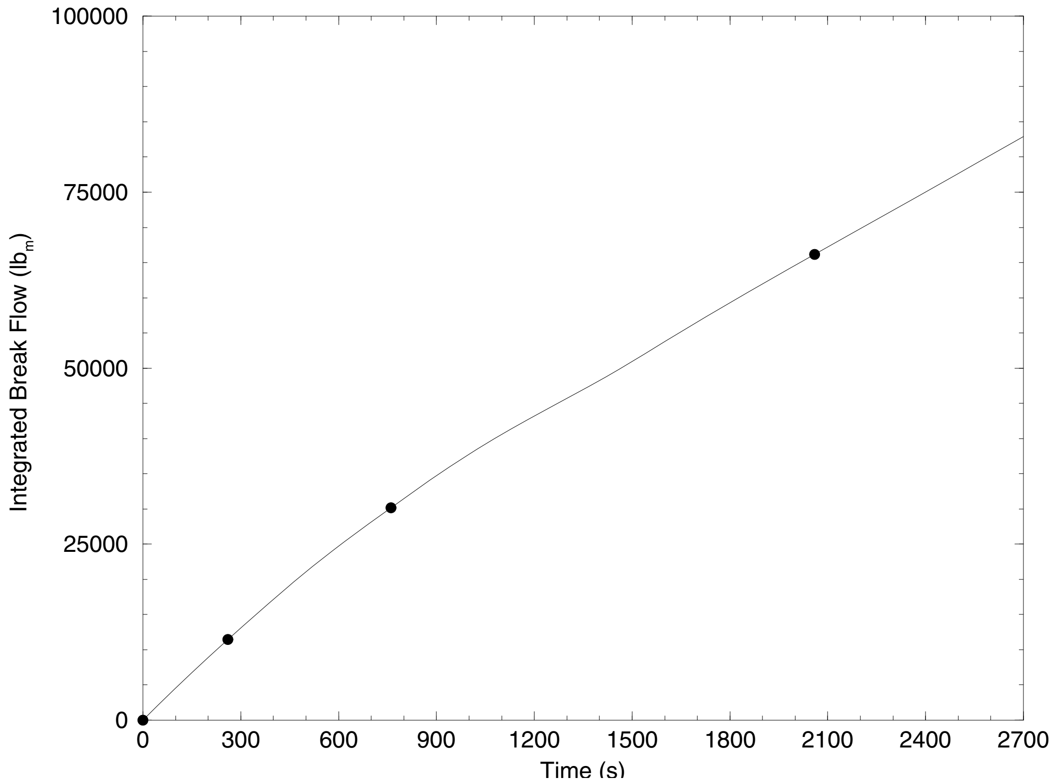


Figure 2.8.5.6.2-11
Steam Generator Tube Rupture
(Hot Side Break)
Integrated Break Flow



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 (ECCS) are provided to mitigate these accidents.

FPL's 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 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;
- 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;
- 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 SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC General Design Criteria (GDC). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC. The current St. Lucie Unit 1 UFSAR (Section 3.1) contains the text for each 1971 criterion as well as a discussion pertaining to design intent.

Specific GDC relevant to ECCS and LOCAs are:

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

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

As noted in UFSAR Sections 3.5, 3.6, 3.7.5, and 3.11, SSCs important to safety are designed to function in the environment created by postulated accidents. Due to the application of leak-before-break methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects associated with circumferential (guillotine) and longitudinal (slot) breaks do not have to be considered. Protective devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles and dynamic loads generated by equipment failures.

- 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 provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3.4 and 4.3. Combined use of control element assemblies (CEAs) and soluble boron 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 functions to inject concentrated boric acid into the RCS for long-term and short-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 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 ECCS is discussed in detail in UFSAR Sections 6.3.2 and 6.3.3. The system is designed to prevent fuel and clad damage that would interfere with the emergency core cooling function for the full spectrum of break sizes, and to limit metal-water reaction. Each of the subsystems is fully redundant. The ECCS design satisfies the criteria specified in 10 CFR 50, Appendix K.

Discussion of the large break LOCA (LBLOCA) analysis is provided in UFSAR Section 15.4.1.2. Discussion of the small break LOCA (SBLOCA) analysis is provided in UFSAR Section 15.3.1.

Discussion of the analysis of LOCA hydraulic forces is provided in UFSAR Section 3.9.1.4. Discussion of the analysis of post-LOCA boron precipitation is provided in UFSAR Appendix 6C, Section 2.4.

Discussion of the realignment guidelines procedures for long-term ECCS operation following a LOCA is provided in UFSAR Appendix 6C, Section 2.5. Discussion of the analysis of post–LOCA criticality is provided in UFSAR Appendix 6C, Section 2.5.1.

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.

2.8.5.6.3.2 Technical Evaluation – Large Break LOCA

2.8.5.6.3.2.1 Introduction

The LBLOCA analysis for EPU is performed by using the AREVA Realistic LBLOCA (RLBLOCA) Methodology/Transition Package. The RLBLOCA methodology and the details of the analyses are described in References 2.8.5.6.3.2-1 and 2.8.5.6.3.2-2. The Reference 2.8.5.6.3.2-2 RLBLOCA Summary Report is included as Appendix C to Attachment 5 of the EPU LAR.

The AREVA RLBLOCA methodology documented in Reference 2.8.5.6.3.2-1 is a NRC-approved methodology for Westinghouse 3-loop, 4-loop and 2X4 Combustion Engineering (CE) plants. The RLBLOCA methodology consists of three approved computer codes. These codes are: (a) RODEX3A for computation of initial fuel stored energy, fission gas release, and fuel-cladding gap conductance; (b) S-RELAP5 for the system calculation; (c) ICECON for the containment back-pressure calculations.

The RLBLOCA methodology is applicable to St. Lucie Unit 1, which is a typical 2X4 CE plant. The input variables and parameters used in the analysis are verified every cycle, as part of the reload process, to be bounding with respect to plant operating and design conditions.

2.8.5.6.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Key inputs and assumptions used in the RLBLOCA analysis for the proposed EPU are contained in LR Tables 2.8.5.6.3-1 and 2.8.5.6.3-2. The plant operating ranges supported by the EPU RLBLOCA analysis are provided in Table 3-2 of Reference 2.8.5.6.3.2-2. The acceptance criteria are discussed below in LR Section 2.8.5.6.3.2.4.

2.8.5.6.3.2.3 Description of Analyses and Evaluations

The LBLOCA analyses have been performed using the AREVA RLBLOCA methodology as documented in Reference 2.8.5.6.3.2-1. The analyses are documented in Reference 2.8.5.6.3.2-2.

2.8.5.6.3.2.4 Results

The analytical models used in the RLBLOCA analysis are consistent with the approved evaluation model (Reference 2.8.5.6.3.2-1). RLBLOCA methodology is a best-estimate method. Comparing with Appendix K method used in the analysis of record (AOR), RLBLOCA methodology provides better results for St. Lucie Unit 1. Except for EPU conditions and the key EPU changes specified in LR Section 2.8.5.0, Accident and Transient Analyses, there are no other major changes required, such as operator actions, Technical Specifications (TS)/Core Operating Limits Report (COLR) changes, and system operating and design parameter changes. Any other changes made are for better representation of the plant parameters.

Analysis results summarized in LR Tables 2.8.5.6.3-3 and 2.8.5.6.3-4 show that the limiting loss of offsite power (LOOP) case has a PCT of 1672°F, and the calculated maximum oxidation thickness and hydrogen generation fall well within regulatory requirements. It is thus demonstrated that the LBLOCA acceptance criteria presented in 10 CFR 50.46(b)(1)-(3) have been met. As discussed in LR Section 2.8.1, Fuel System Design, the changes in core geometry are such that the core remains amenable to cooling. That is, 10 CFR 50.46(b)(4) has been met. The long-term core cooling analysis is discussed in LR Section 2.8.5.6.3.6, Technical Evaluation – Post-LOCA Criticality.

2.8.5.6.3.2.5 References

2.8.5.6.3.2-1 EMF-2103(P)(A), Revision 0, Realistic Large Break LOCA Methodology for Pressurized Water Reactors, Framatome ANP, Inc., April 2003.

2.8.5.6.3.2-2 ANP-2903(P), Revision 0, St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding, AREVA NP Inc., February 2010.

2.8.5.6.3.3 Technical Evaluation – Small Break LOCA

2.8.5.6.3.3.1 Introduction

This section documents the SBLOCA analysis for the EPU. This analysis was performed with the S-RELAP5 methodology (Reference 2.8.5.6.3.3-1). A spectrum of break sizes was analyzed.

St. Lucie Unit 1 is a CE designed pressurized-water reactor (PWR) with two hot legs, four cold legs, and two vertical U-tube steam generators (SGs). The reactor has an EPU core power of 3020 MWt plus 0.3% measurement uncertainty. The reactor vessel (RV) contains a downcomer, upper and lower plenums, and a reactor core containing 217 fuel assemblies. The hot legs connect the RV with the vertical U-tube SGs. Main feedwater (MFW) is injected into the downcomer of each SG. There are three auxiliary feedwater (AFW) pumps, two motor-driven and one turbine-driven. The ECCS contains two high pressure safety injection (HPSI) pumps, four safety injection tanks (SITs), and two low pressure safety injection (LPSI) pumps.

2.8.5.6.3.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Key input parameters and assumptions used in the SBLOCA analysis are contained in LR Table 2.8.5.6.3-5. LR Table 2.8.5.6.3-6 provides the HPSI flow rate as a function of RCS pressure. The input parameters and biasing were consistent with the approved Reference 2.8.5.6.3.3-1 methodology. The 10 CFR 50.46 acceptance criteria are as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.
3. 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 of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.
4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

2.8.5.6.3.3.3 Description of Analyses and Evaluations

The postulated SBLOCA is defined as a break in the RCPB which has an area of up to approximately 10% of a cold leg pipe area. The most limiting break location is in the cold leg pipe on the discharge side of the reactor coolant pump (RCP). This break location results in the largest amount of inventory loss and the largest fraction of ECCS fluid being ejected out through the break. This produces significant core uncovery, the longest fuel rod heatup time, and consequently, the greatest challenge to the 10 CFR 50.46(b)(1)-(4) criteria.

The SBLOCA event is characterized by a slow depressurization of the primary system with a reactor trip occurring on a low pressurizer pressure signal. The safety injection actuation signal (SIAS) occurs when the system has further depressurized. The capacity and shutoff head of the HPSI pumps are important parameters in the SBLOCA analysis. For the limiting break size, the rate of inventory loss from the primary system is such that the HPSI pumps cannot preclude significant core uncovery. The primary system depressurization rate is slow, extending the time required to reach the SIT pressure or to recover core liquid level on HPSI flow. For small break sizes, including the limiting break size, the primary system pressure does not reach the SIT pressure prior to the time of peak cladding temperature. This tends to maximize the heatup time of the hot rod which produces the maximum PCT and local cladding oxidation. Core recovery for the limiting break begins when the safety injection (SI) flow that is retained in the RCS exceeds the mass flow rate out the break, followed by injection of SIT flow.

The Reference 2.8.5.6.3.3-1 methodology has been reviewed and approved by the NRC to perform SBLOCA analyses for CE designed plants such as St. Lucie Unit 1. The appropriate conservatisms, as prescribed by Appendix K of 10 CFR 50, are incorporated. The evaluation model for event response of the primary and secondary systems and hot fuel rod consists of two computer codes. The two AREVA NRC-approved computer codes used in this analysis are:

1. RODEX2-2A determines the burnup-dependent initial fuel rod conditions for the system calculations.
2. S-RELAP5 predicts the thermal-hydraulic response of the primary and secondary sides of the reactor system and the hot rod response.

The RODEX2-2A gap conditions used to initialize S-RELAP5 are taken at end-of-cycle (EOC), consistent with an EOC top-peaked axial power distribution. The use of EOC fuel rod conditions along with an EOC power shape is bounding of beginning- of-cycle (BOC) because: (1) the gap conductance is higher at EOC, (2) the power shape is more top-skewed at EOC, and (3) the initial stored energy, although higher at BOC, has a negligible impact on SBLOCA results since the stored energy is dissipated long before core uncovery.

The RCS was nodalized in the S-RELAP5 model into control volumes interconnected by flow paths or “junctions.” The model includes four SITs, a pressurizer, and two SGs with both primary and secondary sides modeled. All of the loops were modeled explicitly to provide an accurate representation of the plant. A SG tube plugging (SGTP) level of 10% in each SG was modeled, which bounds an average SGTP level of up to 10% with an asymmetry of ±2%. The HPSI system was modeled to deliver the total SI flow asymmetrically to the broken loop and three intact loops in the S-RELAP5 model. LPSI flow was not modeled since the primary system pressure does not fall below the shutoff head of the LPSI pumps until well after the time of PCT is reached. Charging flow from one pump was included in this analysis.

The heat generation rate in the S-RELAP5 reactor core model was determined from reactor kinetics equations with actinide and decay heating as prescribed by Appendix K.

The analysis assumed loss of offsite power concurrent with reactor scram on low pressurizer pressure. The single failure criterion required by Appendix K was satisfied by assuming the loss of one emergency diesel generator (EDG). Thus, a single HPSI pump was assumed to be operable. Charging pump flow was credited in the analysis. Initiation of the HPSI system was delayed by 30 seconds beyond the time of SIAS. The 30-second delay includes the time required for EDG startup and switching. The disabling of a motor-driven AFW pump leaves one motor-driven AFW pump and the turbine-driven AFW pump available. The initiation of the motor-driven AFW pump was delayed 330 seconds beyond the time of the auxiliary feedwater actuation signal (AFAS), indicating low SG level (conservatively assumed in the analysis to be 5.0% narrow range). The turbine-driven AFW pump was not credited in the analysis.

The input model included details of both main steam lines from the SGs to the turbine control valve, including the main steam safety valve (MSSV) inlet piping connected to the main steam lines. The MSSVs were set to open at their nominal setpoints plus 3% tolerance.

Key system parameters and initial conditions used in the analysis are given in LR Table 2.8.5.6.3-5. Relative to the current UFSAR analyses, the analyses supporting the EPU included the following TS/COLR changes in addition to the increased rated thermal power:

- TS SIT minimum pressure was increased from 200 psig to 230 psig.
- TS/COLR peak linear heat rate (LHR) was reduced from 15 kW/ft to 14.7 kW/ft.
- TS/COLR radial peaking limit was reduced from 1.70 to 1.65.
- TS tolerance on the MSSVs was increased from +1% to +3% for Bank 1 and +2% for Bank 2 valves. The analysis conservatively supports these limits by modeling a +3% tolerance for Banks 1 and 2 valves.

Other changes made to the analysis pertain to the better representation of the plant parameters. The HPSI flow used in the analysis is shown in LR Table 2.8.5.6.3-6.

2.8.5.6.3.3.4 Results

SBLOCA break spectrum calculations were performed for break sizes of 0.04 ft^2, 0.05 ft^2, 0.06 ft^2, 0.07 ft^2, 0.08 ft^2, 0.09 ft^2, and 0.10 ft^2. The results for the break spectrum calculations are presented in LR Tables 2.8.5.6.3-7 and 2.8.5.6.3-9. The limiting break size was determined to be 0.06 ft^2. Break sizes larger than 0.10 ft^2 are less limiting due to faster RCS depressurization and earlier timing of SIT flow. While the PCT for the 0.04 ft^2 break is slightly higher than the PCT for the 0.05 ft^2 break (attributed mainly to differences in loop seal clearing phenomena), the trend in PCT is expected to decrease as the break size decreases below 0.04 ft^2. This is due to the fact that as the break size becomes smaller, the break flow becomes smaller such that the ability of the HPSI flow to maintain RCS mass and limit core uncovery becomes greater. This will result in lower PCTs for break sizes less than 0.04 ft^2. Predicted event times are summarized in Table 2.8.5.6.3-8 for the break spectrum calculations.

The results for the limiting break size (0.06 ft^2) are shown in LR Figures 2.8.5.6.3-1 through 2.8.5.6.3-13. The following discussion pertains to the limiting case. System behavior for the other cases was similar, although event timings were different.

The primary and secondary pressure responses are shown in LR Figure 2.8.5.6.3-2. The primary pressure decreased immediately after break initiation. When the primary pressure reached the thermal margin/low pressure (TM/LP) trip setpoint of 1807 psia, reactor scram occurred (LR

Figure 2.8.5.6.3-1). SG isolation at reactor trip caused the secondary pressure to increase rapidly until the MSSVs opened, causing the secondary pressure to stabilize.

The primary coolant pumps were assumed to trip at reactor scram due to an assumed LOOP at reactor trip, which resulted in decreasing loop flow (LR Figure 2.8.5.6.3-6).

The break flow rate is shown in LR Figure 2.8.5.6.3-4. Single phase liquid flow began at the initiation of the break and continued until about 225 seconds when primary pressure reached saturation pressure and the break flow became a two-phase mixture. The decrease in flow rate at about 465 seconds was due to the transition from two-phase flow to single-phase vapor flow, which occurred following loop seal clearing.

The total HPSI flow rate is shown in LR Figure 2.8.5.6.3-10. At approximately 146 seconds, HPSI flow began and increased as primary system pressure decreased. SIT flow began at approximately 2370 seconds.

LR Figure 2.8.5.6.3-5 shows void fraction in the loop seals. The loop seals in loops 1A, 2A, and 2B (broken loop) did not clear. LR Figure 2.8.5.6.3-3 shows that the break flow transitioned to single-phase steam following loop seal clearing.

The primary system and RV fluid masses, shown in LR Figure 2.8.5.6.3-11, declined rapidly after event initiation, and the RV mass reached a minimum at 1674 seconds.

The hot assembly collapsed liquid level is shown in LR Figure 2.8.5.6.3-12. The collapsed liquid level fell below the top of the core (11.39 feet) immediately after the break opened. The rate at which the level fell decreased after the break flow became two-phase (approximately 225 seconds). The hot spot uncovery began at approximately 1014 seconds, as shown by the increasing hot rod temperature in LR Figure 2.8.5.6.3-13. The collapsed liquid level continued to decrease until HPSI flow was sufficient to overcome the break flow and recover RCS mass.

The PCT occurred at 2166 sec.

10 CFR 50.46(b)(1)-(4) criteria have been demonstrated to be met for the limiting case:

1. The limiting PCT was calculated to be 2072°F.
2. The maximum local oxidation was calculated to be 11.06% of the total cladding thickness before oxidation.
3. The maximum total core oxidation was calculated to be 0.156% of the maximum hypothetical amount for the active core.
4. The core remains amenable to cooling by staying within the local oxidation criteria.

2.8.5.6.3.3.5 References

2.8.5.6.3.3-1 EMF-2328(P)(A), Revision 0, PWR Small Break LOCA Evaluation Model, S-RELAP5 Based, Framatome ANP, Inc., March 2001.

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 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

For the purpose of analyzing the LOCA hydraulic blowdown loads, FPL participated in an Asymmetric Loads Evaluation Generic Plant Program that selected Calvert Cliffs Unit 1 as the analyzed plant design. These generic plant analyses considered the large mechanistic breaks in the main coolant loop piping, at the RV inlet nozzle and at the RV outlet nozzle, using the CEFLASH-4B computer code (Reference 2.8.5.6.3.4-1).

The results of this computer analysis were applied to the plants that participated in the Generic Plant Program, including St. Lucie Unit 1. The main differences between the generic plant and St. Lucie Unit 1 were that St. Lucie Unit 1 had a thermal shield and an RV volume that was 2% lower. The blowdown loads results of the generic plant were shown to be applicable to the St. Lucie Unit 1 RCS asymmetric loads structural analysis.

To support removal of the thermal shield of St. Lucie Unit 1 (circa 1984), power increase from 2611 MWt to 2754 MWt (including measurement uncertainty), and core inlet temperature increase from 548°F to 551°F, evaluations concluded that the blowdown loads calculated for the generic plant continued to be applicable for St. Lucie Unit 1 without the thermal shield at the changed conditions.

Accordingly, the calculation of blowdown loads for the generic plant serves as the AOR, against which the loads at EPU conditions were assessed.

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 up to 10%.
- Nominal vessel flow rate corresponding to the SGTP.

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 calculations based on the generic plant. This assessment was performed to be demonstrable for core inlet temperatures from 546°F and higher, and SGTP of 0% through 10%.

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

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.)

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 is increased by 2°F to 551°F, 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. There is no change to the system pressure due to EPU.

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 can affect the blowdown loads due to a hot-side break. For EPU, the best estimate RCS flow is unchanged, and the minimum RCS flow is increased from 365,000 gpm to 375,000 gpm.

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 core power is increased from 2700 MWth to 3020 MWth due to EPU.

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. Changes may influence the calculated axial blowdown loads on the RV internals and fuel, principally by affecting the wave frequencies and initial static loadings. For EPU, the fuel assembly grid design is unchanged, and therefore will not affect blowdown loads.

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 leak-before-break (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 main loop piping ruptures that had been analyzed for the design basis:

  - Mechanistic double-ended guillotine break at the RV inlet nozzle (1414 in^2);
  - Mechanistic guillotine break at the RV outlet nozzle (135 in^2).

  The assessment considered the impact of the EPU conditions for ruptures of tributary piping attached to the RCS main loop:

  - Safety injection nozzle on the cold leg (102.7 in^2)
  - Surge line nozzle on the hot leg (101.6 in^2).

  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 ruptures of main coolant loop piping on which the original plant design basis analyses were based.

  The impact of replacing the large pipe ruptures with tributary line breaks per LBB is determined by two opposing factors, the break size and its opening time. The general observation that application of LBB reduces the blowdown loads implies that the effect of a smaller break size trumps the effect of a shorter opening time. This is valid for the above cold-side breaks, with a break area reduction of 14:1.

  However, the area reduction for the above hot-side breaks is only 1.33-to-1. The assessment considered this, and concluded that the LBB-based surge line break blowdown loads would compare favorably to those of the main-pipe hot leg break of the design basis, as long as the hot leg coolant temperature is not significantly lower. (The pre-EPU installation of replacement SGs increased the primary coolant flow rate, thereby lowering the hot leg temperature. However, this effect was more than matched by the increased core thermal power due to EPU.)

Steam Generator Tube Plugging. 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.
- 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.
- 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% SGTP would provide the lowest hot leg temperature.

The maximum allowed SGTP is reduced to 10% for EPU, whereas the minimum SGTP and the corresponding RCS flow remain unchanged due to EPU.

The assessment demonstrated sequentially the continued applicability of the AOR blowdown loads based on the generic plant to St. Lucie Unit 1 with the following EPU conditions, which bound the potential nominal plant conditions:

- Nominal core inlet temperature of 551°F and SGTP of 0% through 10%, for a rupture of the main loop piping;
- Minimum core inlet temperature of 548°F and SGTP of 0% through 10%, for breaks of tributary lines per LBB;
- Reduced core inlet temperature of 546°F and SGTP of 0% through 10%, for breaks of tributary lines per LBB.

2.8.5.6.3.4.4 Results

The assessment concluded that the blowdown loads on the reactor vessel internals and fuel that were calculated for the generic plant will bound the loads at the EPU conditions with 551°F core inlet temperature and 0% 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% through 10%. The blowdown loads from the AOR based on the generic plant continue to be applicable to the St. Lucie Unit 1 RCS asymmetric loads structural analysis over this extended range of conditions. This extended-range conclusion applies to breaks of tributary lines per LBB.

2.8.5.6.3.4.5 References

2.8.5.6.3.4-1 CENPD-252-P-A, Blowdown Analysis Method – Method for Analysis of Blowdown Induced Forces in a Reactor Vessel, July 1979.

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, with an increase in the minimum simultaneous hot and cold side injection flow rate, is acceptable with respect to post-LOCA long-term cooling Criterion 5 of 10 CFR 50.46, ECCS acceptance criteria (Reference 2.8.5.6.3.5-1).

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 2.8.5.6.3.5-3), with the exceptions described below. This evaluation model complies with the requirements of Appendix K to 10 CFR 50 (Reference 2.8.5.6.3.5-2) and was NRC accepted for referencing in licensing applications for CE PWRs.

However, in a letter dated August 1, 2005 (Reference 2.8.5.6.3.5-4), 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."*

Based on discussions with the NRC staff, Westinghouse understands that the issues identified in Reference 2.8.5.6.3.5-4 must be addressed to the staff's satisfaction for any plant change that impacts the post-LOCA long-term cooling analysis and that requires NRC approval before implementation (e.g., a change that requires a license amendment, such as an EPU). This understanding was confirmed by the NRC in a letter dated November 23, 2005 (Reference 2.8.5.6.3.5-5), 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 2.8.5.6.3.5-4. The four items identified in Reference 2.8.5.6.3.5-5 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.
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 EPU. The methodology used in the Waterford 3 EPU boric acid precipitation analysis has since become known as the “Waterford approach.” It has been recognized by the NRC (Reference 2.8.5.6.3.5-6) as an acceptable interim methodology for performing boric acid precipitation analyses prior to the establishment of a new approved methodology that addresses the issues identified in Reference 2.8.5.6.3.5-4.

The St. Lucie Unit 1 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 for St. Lucie Unit 1 addressed the four items identified in Reference 2.8.5.6.3.5-5.

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 St. Lucie Unit 1 EPU boric acid precipitation analysis are given in LR Table 2.8.5.6.3-10.

Assumptions

The boric acid precipitation analysis was performed with the BORON computer code (Reference 2.8.5.6.3.5-3, 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-54-P-A post-LOCA boric acid precipitation analysis. 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 1 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 staff for computing the mixture level in the core following all small break LOCAs (References 2.8.5.6.3.5-7, 2.8.5.6.3.5-8, and 2.8.5.6.3.5-9). 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.

   Lastly, the mixing volume included only 50% of the lower plenum region of the reactor vessel. 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% of this volume is conservative.

   In summary the methodology change to the mixing volume in the Waterford approach, and used for St. Lucie Unit 1, 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).
- The mixing volume included 50% 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 safety injection flows.

2. The boric acid makeup (BAM) tank 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 BAM tank concentration used is 6240 ppm, whereas the RWT maximum concentration is conservatively set at 2600 ppm. The previously approved model assumed that the BAM tank 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.

<u>Analysis Assumptions Made Since the Waterford Approach</u>

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).

1. Decay heat is represented with the 1973 ANS Standard (Reference 2.8.5.6.3.5-3). In accordance with NRC Item #4 (listed in 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 2.8.5.6.3.5-3), the analysis traditionally used a decay heat multiplier of 1.2 up to 1000 seconds and 1.1 thereafter.

2. The mixing volume 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 60% for conservatism and the geometric losses were conservatively modeled with an RCP locked rotor hydraulic loss coefficient.

3. 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 2.8.5.6.3.5-3, the solubility limit at 14.7 psia (i.e., at 212°F) is 27.6 weight percent (w/o). 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 was based on the following assumptions and features:

1. Boric acid precipitation is prevented by producing a flushing flow through the core via safety injection flows (see LR Section 2.8.5.6.3.5.3). For a cold leg break, there is no natural flushing flow, as the safety injection flow would tend to flow around the downcomer and exit the cold legs without being forced through the reactor vessel. For hot leg breaks, however, there is a natural flushing flow created by the safety injection 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, 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. Therefore, the use of a large cold leg break scenario is intended to be bounding for all break sizes and locations.

2. The boric acid concentration is treated as spatially uniform within the mixing volume, i.e., complete mixing. This has been confirmed by laboratory testing.

3. Uniform concentration of boric acid in the containment sump was assumed. Entrapment of sump fluid in isolated cavities was not considered.

4. 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.

5. 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.
6. 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.
7. 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.
8. 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 emergency diesel generator, 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.
9. 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.
10. 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 1 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 reactor vessel 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 safety injection flow to the cold legs provides hydrostatically driven flushing flow through the reactor vessel.

- Minimum Creditable Downcomer Head – The reactor vessel 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 reactor vessel 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 reactor coolant pump 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 steam generator, loop seal, and the assumed locked rotor of the reactor coolant pump 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 steam generator, loop seal, and locked rotor of the reactor coolant pump. 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 large break LOCA scenario is bounding for all break sizes and locations for boric acid precipitation analyses. The large break LOCA transient results in a low reactor coolant system 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 safety injection subcooling for increased heat removal.

<u>Basis for the Selection of the Height of the Mixing Volume</u>

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 reactor vessel 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 reactor vessel 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 reactor vessel 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 1:

$$\Delta P_{OP} = \Delta P_{DC} - \Delta P_{STM} - \Delta P_{CORE} \qquad \text{Equation 1}$$

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 four different times (1, 4, 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 15.72 feet for St. Lucie Unit 1.

The specific volume of saturated liquid at 14.7 psia is 0.016714 ft^3/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:

$$\Delta P_{DC} = 15.72 \text{ ft}/0.016714 \text{ ft}^3/\text{lbm}/144 \text{ in.}^2/\text{ft}^2 * g/g_c = 6.53 \text{ psi} \quad \text{Equation 2}$$

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 3:

$$\Delta P_{STM} = K * v/9266.112 * (W/A)^2 \quad \text{Equation 3}$$

where

K	=	K-factor (friction and geometric loss coefficients, dimensionless)
v	=	specific volume of steam at 14.7 psia = 26.7952 ft^3/lbm
A	=	area (ft^2)
W	=	core boil off steam flow rate (lbm/sec)

Units Conversion: 9266.112 = the product of 2*g_c (32.174 lbm-ft/lbf-sec^2)*144 in.^{2}/ft^2. Its units are, therefore, lbm-in.^{2}/lbf-sec^2-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 4. Using a time of 1 hour, or 3600 seconds, the DHF is:

$$DECAY = 0.75*10^{(0.75*\log T - 0.778)}/T \quad \text{Equation 4}$$

where

DECAY	=	normalized decay heat fraction including 1.1 conservative multiplier
T	=	time (seconds)
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) = 0.016143 * 1.2/1.1 = 0.01761

The core power level including power measurement uncertainty is 3030 MWt for EPU conditions for St. Lucie Unit 1.

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 5:

WBO = 3030 MWt * 948.04 Btu/sec-MWt * 0.01761/1150.28 - 180.18) Btu/lbm
= 52.15 lbm/sec — Equation 5

This calculation is repeated at three additional times (4, 5, and 6 hours) to cover the time frame of this comparative analysis for St. Lucie Unit 1 at EPU conditions. The following table summarizes the core boil-off for all four times.

Time (hr)	Time (sec)	DHF	DHF (w/1.2)	WBO
1	3600	0.016143	0.017611	52.15
4	14400	0.011415	0.012453	36.87
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 160 for St. Lucie Unit 1. This geometric K-factor contains an additional 10% conservative margin for uncertainty in the geometric losses in the reactor vessel and 20% for geometric losses in the remainder of the reactor coolant system. The friction resistance, FK, was also obtained using plant-specific pressure drop data, and is calculated to be 37.534 for St. Lucie Unit 1. 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 60 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:

Total K-Factor = GK + FK = 160 + 60 = 220

The core-to-break steam flow pressure drop is calculated using Equation 3:

$$\Delta P_{STM} = K * v/9266.112 * (W/A)^2$$

$$\Delta P_{STM} = (220 * 26.7952\ ft^3/lbm)/9266.112 * (52.15\ lbm/sec/54.00\ ft^2)^2$$
$$= 0.593\ psi$$

Again, the calculation of ΔP_{STM} was repeated for all times mentioned above for EPU conditions for St. Lucie Unit 1. The following table summarizes ΔP_{STM} for all four calculated times post-LOCA.

Time (hr)	Time (sec)	ΔP_{STM} (psi)
1	3600	0.593
4	14400	0.297
5	18000	0.265
6	21600	0.242

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. For St. Lucie Unit 1 at EPU conditions, the liquid volume in the active core at 1 hour post-LOCA is determined to be 160.43 ft^3. 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 54.00 ft^2, and the specific volume of saturated liquid at 14.7 psia is 0.016714 ft^3/lbm. Based on this data and using Equation 2, the core hydrostatic pressure drop, ΔP_{CORE} at 1 hour post-LOCA is:

$$\Delta P_{CORE} \quad = \quad (160.43\ ft^3/54.00\ ft^2)/0.016714\ ft^3/lbm/144\ in.^2/ft^2 * g/g_c = 1.23\ psi$$

The following table summarizes ΔP_{CORE} for all four 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	1.23
4	14400	1.51
5	18000	1.56
6	21600	1.60

Hydrostatic Head of the Outlet Plenum, ΔP_{OP}

The following hydrostatic pressure balance, given earlier as Equation 1, is used to calculate the hydrostatic head of the outlet plenum:

$$\Delta P_{OP} \quad = \quad \Delta P_{DC} - \Delta P_{STM} - \Delta P_{CORE}$$

ΔP_{DC}, ΔP_{STM}, and ΔP_{CORE} have been calculated above for four different times in the transient post-LOCA for EPU conditions of St. Lucie Unit 1. 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 6 as follows:

$$H_{OP}\text{, ft} = \Delta P_{OP}\text{, psi} * v\text{, ft}^3/\text{lbm} * 144 \text{ in.}^2/\text{ft}^2 * g/g_c \qquad \text{Equation 6}$$

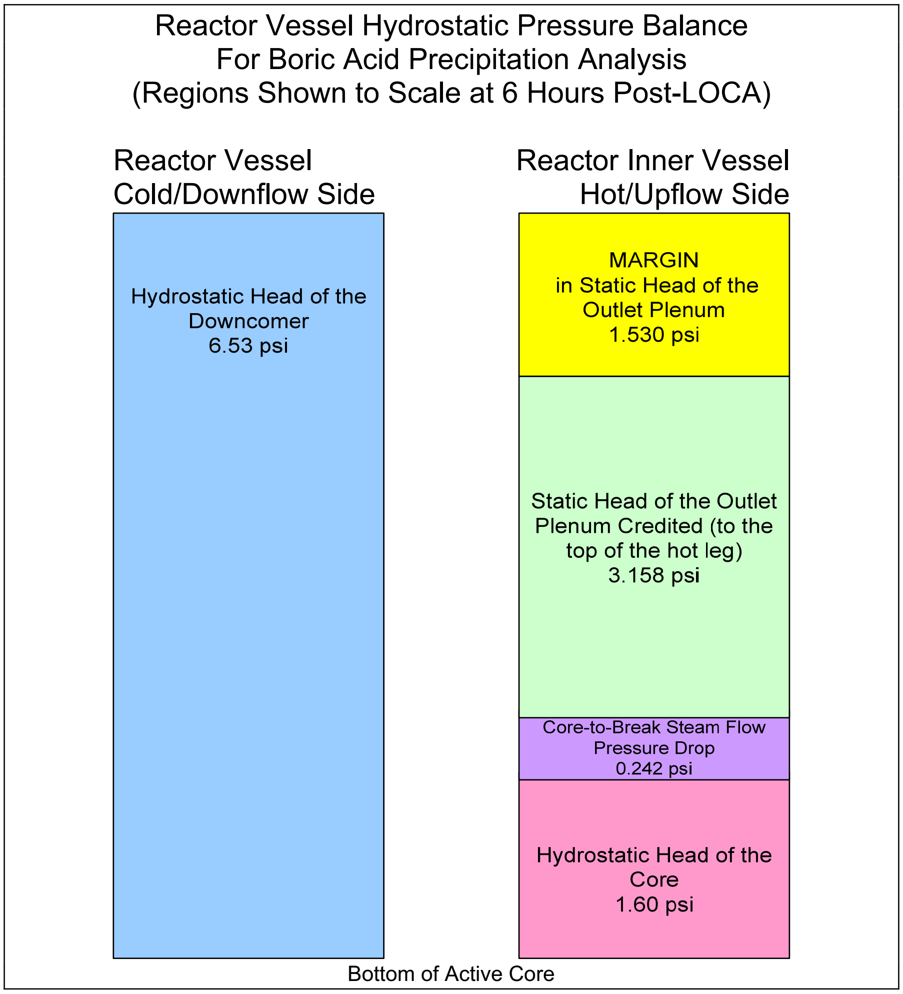
Since this height was derived from the pressure drop, it represents the collapsed height of the liquid in the outlet plenum, which is conservative for justifying the impact of the break configuration on the mixing volume. If this value was converted to a froth height based on the void fraction of the 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%, 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)	Hop (ft)
1	3600	6.53	0.593	1.23	4.707	11.33
4	14400	6.53	0.297	1.51	4.723	11.37
5	18000	6.53	0.265	1.56	4.705	11.32
6	21600	6.53	0.242	1.60	4.688	11.28

From this table, the lowest static head of the outlet plenum occurs at 6 hours, when the pressure drop through the core is highest, and is 11.28 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.” Also, this time corresponds to the latest time considered before switchover to simultaneous hot and cold side injection, where boric acid concentration is the highest.

While this demonstrates that at a minimum there is 11.28 feet available for the mixing volume in the outlet plenum, the analysis only credits up to the top of the hot leg (or 7.60 feet). When converted to a pressure drop using Equation 6, the analysis-credited height to the top of the hot leg of 7.60 feet is equivalent to 3.158 psi. Therefore, for a double-ended guillotine break, at 6 hours post-LOCA, there is 1.530 psi of margin in the hydrostatic balance. The following diagram visually depicts this hydrostatic balance at 6 hours for EPU conditions for St. Lucie Unit 1, including the available margin in the outlet plenum.



As can be seen for this limiting break configuration, there is 1.530 psi of margin (more than 23% of the hydrostatic head of the downcomer) in the hydrostatic pressure balance between the hot and cold sides of the reactor vessel.

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 2.8.5.6.3-10, the height of the loop seal (from top of cross-over leg to bottom of discharge leg) is 3.5 ft for St. Lucie Unit 1. The static head associated with the height of liquid in the cold leg above the loop seal inlet to the reactor coolant pump is offset by the added static head for the downcomer from this liquid. Using Equation 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 1.530 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 safety injection 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 2.8.5.6.3.5-1). 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.”*

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 safety injection 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 safety injection lineup to the cold legs, i.e., safety injection 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 safety injection flow exits the break and is not forced through the reactor vessel, 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 reactor vessel 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 uncovery could occur. Initiating simultaneous hot and cold side injection no earlier than when the core boil-off drops below the combined injection to the reactor vessel (after accounting for spillage out the break) prevents the potential for core uncovery after the switch-over to simultaneous hot and cold side injection. 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 w/o). 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 reactor vessel 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

Post-LOCA Boric Acid Precipitation

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 2.8.5.6.3-11. The boric acid precipitation analysis determined that minimum simultaneous hot and cold side injection flow rates of 250 gpm to the hot side and 275 gpm to the cold side of the RCS, initiated between four and six hours post-LOCA, maintains the boric acid concentration in the core below the solubility limit of 27.6 w/o for the limiting break, i.e., a large cold leg break. Furthermore, with an injection of 250 gpm to the hot side and 275 gpm to the cold side 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 26.6 w/o, a margin of 1 w/o to 27.6 w/o. In addition, it was shown that a flushing flow rate of 20 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 seven hours. LR Figure 2.8.5.6.3-14 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 w/o 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 2.8.5.6.3-15 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 increased the required minimum simultaneous hot and cold side injection flow rate as follows: (1) from 190 gpm for the current condition to 250 gpm to the hot side for the EPU, and (2) from 235 gpm for the current condition to 275 gpm to the cold side for the EPU. A modification is required to guarantee a minimum hot and cold side injection flow rate of 250 gpm to the hot side and 275 gpm to the cold side to be available within the four to six hour window post-LOCA for the EPU.

The EPU post-LOCA boric acid precipitation analysis demonstrated that the four to six hour switchover time window for simultaneous injection remains acceptable to control boric acid concentration and prevent boron precipitation in the core. The margin to precipitation was determined to be approximately 1 w/o. 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 reactor vessel meets or exceeds the core boil-off rate at the early end of the switchover time window.

Post-LOCA Results that are Input to the Realignment Guidelines Procedures Changes

The long-term cooling analysis provides the basis for the value for the time window for initiating simultaneous hot and cold side injection in the LOCA emergency operating procedure (EOP). As noted above, the time window determined by this analysis is four to six hours post-LOCA. This result is consistent with the current EOP hot and cold side injection window and no change to the LOCA injection flow realignment guideline in the EOP is required for EPU. However, the time window is changed relative to the current post-LOCA analysis results, which demonstrated a suitable window to be four to ten hours post-LOCA.

Boric Acid Precipitation for Small Breaks

Current EOPs, which are configured for a “hot shutdown” plant, ensure that post-LOCA operator actions and functional recovery guidelines promote forced cooldown to maintain adequate cooling and to keep the core covered by a two-phase fluid in the long-term for EPU. Analyses were performed to confirm that the EPU post-LOCA boric acid precipitation analysis would be applicable regardless of break size. These analyses confirmed that the large break boric acid precipitation analysis with simultaneous hot and cold side injection initiated in the four to six hour window would ensure adequate boric acid flushing and decay heat removal for “large break” sizes. Additional analyses were performed assuming a refilled RCS, which demonstrated that sufficient natural circulation was maintained to disperse boric acid throughout the primary system and rely on shutdown cooling for long-term decay heat removal for “small break” sizes. These analyses determined an overlap between the break sizes of the “small breaks” and “large breaks,” thus assuring valid cooling and boric acid control methods for all break sizes.

2.8.5.6.3.5.5 References

2.8.5.6.3.5-1 Code of Federal Regulations, Title 10, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors.

2.8.5.6.3.5-2 Code of Federal Regulations, Title 10, Part 50, Appendix K, ECCS Evaluation Models.

2.8.5.6.3.5-3 CENPD-254-P-A, Post-LOCA Long Term Cooling Evaluation Model, June 1980.

2.8.5.6.3.5-4 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)

2.8.5.6.3.5-5 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)

2.8.5.6.3.5-6 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)

2.8.5.6.3.5-7 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.

2.8.5.6.3.5-8 CENPD-137, Supplement 1-P, Small Break Model, Calculative Methods for the C-E Small Break LOCA Evaluation Model, January 1977.

2.8.5.6.3.5-9 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.

2.8.5.6.3.6 Technical Evaluation – Post-LOCA Criticality

2.8.5.6.3.6.1 Introduction

This evaluation is concerned with core re-criticality following a LBLOCA. Core re-criticality could occur after the ECCS has been re-aligned from cold leg to hot/cold leg recirculation. Following the blowdown period of a large cold leg LOCA, the reactor core is refilled by the ECCS using water stored in the RWT and SITs. Decay heat boils the entering SI water for an extended period of time, which increases the core boron concentration. Boiling in the core increases the boron concentration in the core region, and the sump boron concentration decreases as the steam leaving the core and exiting the RCS through the cold leg break condenses in the containment and returns to the sump. When the ECCS switchover to hot/cold leg recirculation occurs, the core boron concentration could be reduced to the sump boron concentration by back flushing the core contents via hot leg injection through the existing cold leg break. As a result, the core could return to a critical state if the sump boron concentration is sufficiently low at the time of switchover to hot/cold leg recirculation.

2.8.5.6.3.6.2 Input Parameters, Assumptions, and Acceptance Criteria

The evaluation used the following key input parameters and assumptions:

- RCS volume excluding the volume occupied by steam in the pressurizer was used.
- TS minimum usable RWT volume was used to conservatively minimize the containment sump boron concentration
- A conservative large holdup volume was used to account for inventory not reaching the containment sump.
- TS lower range liquid volume in the SIT was used.
- Pre-LOCA RCS boron concentration and post-LOCA critical boron concentration were used consistent with the core design.
- Minimum TS boron concentrations in the RWT and SITs were used.
- Minimum xenon worth was credited.
- It was assumed that the plant has operated at rated power plus uncertainty prior to the accident. Decay heat was modeled with 20% uncertainty plus actinides.
- To maximize the dilution of the containment sump boron, the liquid exiting the core and the RCS was assumed to have a boron concentration of 0 ppm, i.e., all of the boron remains in the RCS.

The acceptance criterion for this evaluation is to ensure that the containment sump boron concentration remains greater than the post-LOCA critical boron concentration at the time of ECCS switchover to hot/cold leg recirculation.

2.8.5.6.3.6.3 Description of Analyses and Evaluations

The evaluation consisted of a mass balance calculating the containment sump boron concentration as a function of time. The liquid being boiled-off in the core was assumed to contain no boron. As it falls back into the containment sump, the containment sump boron concentration becomes diluted. The resulting diluted containment sump boron concentration is then injected back into the core where water is boiled-off returning no boron to the containment sump. The boron concentration of the liquid in the sump, being injected back into the core, was compared against the critical boron concentration.

2.8.5.6.3.6.4 Results

The results of this analysis demonstrated that the core will remain subcritical as long as the time for switchover to hot/cold leg recirculation is less than 12 hours. Since, as discussed in LR Section 2.8.5.6.3.5, the switchover time window is four to six hours, the core will remain subcritical following a LBLOCA.

2.8.5.6.3.7 Evaluation of 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.

2.8.5.6.3.8 Conclusion

FPL has analyzed the LOCA events for evaluating ECCS performance. 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 reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, 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.

Table 2.8.5.6.3-1
Statistical Distributions Used in RLBLOCA Analysis for Process Parameters(1)

Parameter	Operational Uncertainty Distribution	Parameter Range
Pressurizer pressure (psia)	Uniform	2210–2290
Pressurizer liquid level (percent)	Uniform	62.6–68.6
SIT liquid volume (ft^3)	Uniform	1090.0–1170.0
SIT pressure (psia)	Uniform	214.7–294.7
Containment temperature (°F)	Uniform	115.5–124.5
Containment volume (ft^3)	Uniform	2.461E+6–2.637E+6
Initial RCS flow rate (Mlbm/hr)	Uniform	140.8–164.6
Initial RCS operating temperature (T_{cold}) (°F)	Uniform	548.0–554.0
RWST temperature for ECCS (°F)	Point	104
Offsite power availability(2)	Binary	0,1
Delay for containment spray (s)	Point	0
LPSI pump delay (s)	Point	19.5 (with offsite power) 30.0 (without offsite power)
HPSI pump delay (s)	Point	19.5 (with offsite power) 30.0 (without offsite power)

1. The core power is not sampled.
2. This is no longer a sampled parameter. One set of 59 cases is run with LOOP and one set of 59 cases is run with No-LOOP.

Table 2.8.5.6.3-2
RLBLOCA Methodology SER Conditions and Limitations

SER Conditions and Limitations	Response
1. A CCFL violation warning will be added to alert the analyst to CCFL violation in the downcomer should such occur.	There was no significant occurrence of CCFL violation in the downcomer for this analysis. Violations of CCFL were noted in a statistically insignificant number of time steps.
2. AREVA NP has agreed that it is not to use nodalization with hot leg to downcomer nozzle gaps.	Hot leg nozzle gaps were not modeled.
3. If AREVA NP applies the RLBLOCA methodology to plants using a higher planar linear heat generation rate (PLHGR) than used in the current analysis, or if the methodology is to be applied to an end-of-life analysis for which the pin pressure is significantly higher, then the need for a blowdown clad rupture model will be reevaluated. The evaluation may be based on relevant engineering experience and should be documented in either the RLBLOCA guideline or plant specific calculation file.	The PLHGR for St. Lucie Unit 1 is lower than that used in the development of the RLBLOCA EM (Reference 2.8.5.6.3.2-1). An end-of-life calculation was not performed; thus, the need for a blowdown cladding rupture model was not reevaluated.
4. Slot breaks on the top of the pipe have not been evaluated. These breaks could cause the loop seals to refill during late reflood and the core to uncover again. These break locations are an oxidation concern as opposed to a PCT concern since the top of the core can remain uncovered for extended periods of time. Should an analysis be performed for a plant with spillunder (Top crossover pipe (ID) at the crossover pipes lowest elevation) that are below the top elevation of the core, AREVA NP will evaluate the effect of the deep loop seal on the slot breaks. The evaluation may be based on relevant engineering experience and should be documented in either the RLBLOCA guideline or plant-specific calculation file.	For St. Lucie Unit 1, the elevation of the cross-over piping top (ID) relative to the cold leg center line is -57 inches, and the elevation of the top of the active core relative to the cold leg center line is -66.235 inches. Therefore, no evaluation is required.
5. The model applies to 3 and 4 loop Westinghouse- and CE-designed nuclear steam systems.	St. Lucie Unit 1 is a CE-designed 2X4 loop plant.

Table 2.8.5.6.3-2 (Continued)
RLBLOCA Methodology SER Conditions and Limitations

SER Conditions and Limitations	Response
6. The model applies to bottom reflood plants only (cold side injection into the cold legs at the reactor coolant discharge piping).	St. Lucie Unit 1 is a bottom reflood plant.
7. The model is valid as long as blowdown quench does not occur. If blowdown quench occurs, additional justification for the blowdown heat transfer model and uncertainty are needed or the calculation is corrected. A blowdown quench is characterized by a temperature reduction of the peak cladding temperature (PCT) node to saturation temperature during the blowdown period.	The limiting case did not show any evidence of a blowdown quench.
8. The reflood model applies to bottom-up quench behavior. If a top-down quench occurs, the model is to be justified or corrected to remove top quench. A top-down quench is characterized by the quench front moving from the top to the bottom of the hot assembly.	Core quench initiated at the bottom of the core and proceeded upward.
9. The model does not determine whether Criterion 5 of 10 CFR 50.46, long-term cooling, has been satisfied. This will be determined by each applicant or licensee as part of its application of this methodology.	Long-term cooling was not evaluated in this analysis.
10. Specific guidelines must be used to develop the plant-specific nodalization. Deviations from the reference plant must be addressed. =	The nodalization in the plant model is consistent with the CE-designed 2X4 loop sample calculation that was submitted to the NRC for review. Reference 2.8.5.6.3.2-2, Figure 3-1 shows the loop noding used in this analysis. (Note only Loop 1 is shown in the figure; Loops 2 and 3 are identical to Loop 1, except that only Loop 1 contains the pressurizer and the break.) Figure 3-2 shows the steam generator model. Figures 3-3, 3-4, and 3-5 show the reactor vessel noding diagrams.

Table 2.8.5.6.3-2 (Continued)
RLBLOCA Methodology SER Conditions and Limitations

SER Conditions and Limitations	Response
11. A table that contains the plant-specific parameters and the range of the values considered for the selected parameter during the topical report approval process must be provided. When plant-specific parameters are outside the range used in demonstrating acceptable code performance, the licensee or applicant will submit sensitivity studies to show the effects of that deviation.	Simulation of clad temperature response is a function of phenomenological correlations that have been derived either analytically or experimentally. The important correlations have been validated for the RLBLOCA methodology and a statement of the range of applicability has been documented. The correlations of interest are the set of heat transfer correlations as described in Reference 2.8.5.6.3.2-1. Reference 2.8.5.6.3.2-2, Table 3-7 presents the summary of the full range of applicability for the important heat transfer correlations, as well as the ranges calculated in the limiting case of this analysis. Calculated values for other parameters of interest are also provided. As is evident, the plant-specific parameters fall within the methodology's range of applicability.
12. The licensee or applicant using the approved methodology must submit the results of the plant-specific analyses, including the calculated worst break size, PCT, and local and total oxidation.	Analysis results are discussed in Reference 2.8.5.6.3.2-2, Section 3.5.
13. The licensee or applicant wishing to apply AREVA NP realistic large break loss-of-coolant accident (RLBLOCA) methodology to M5 clad fuel must request an exemption for its use until the planned rulemaking to modify 10 CFR 50.46(a)(i) to include M5 cladding material has been completed.	Not Applicable

Table 2.8.5.6.3-3
LBLOCA Results and Comparison to Previous Results

	RLBLOCA Results for the Limiting Case (Table 3-5 in Reference 2.8.5.6.3.2-2)	Current UFSAR Analysis
PCT		
Temperature	1672°F	2005°F
Time	26.6s	151.9s
Elevation	3.406 ft	10.53 ft
Metal-Water Reaction		
Percent oxidation maximum	0.6517%	5.38%
Percent total oxidation	0.0381%	<1.0%

Table 2.8.5.6.3-4
RLBLOCA Results

10 CFR 50.46 Requirement	RLBLOCA Results for the Limiting PCT Case	Criteria
PCT	1672°F	<2200°F
Percent oxidation maximum	0.6517%	17%
Percent total oxidation	0.0381%	<1%

Table 2.8.5.6.3-5
SBLOCA System Parameters and Initial Conditions

Reactor power, MWt	**3020 + 0.3% measurement uncertainty**
Peak LHR, kW/ft	14.7
Radial peaking factor (1.65 plus uncertainty)	1.749
RCS flow rate, gpm	375,000
Pressurizer pressure, psia	2250
Core inlet coolant temperature, °F	551
SIT pressure, psia	244.7
SIT fluid temperature, °F	120
SG tube plugging level, %	10
SG secondary pressure, psia	830
MFW temperature, °F	436
AFW temperature, °F	70
Low SG level AFAS setpoint, %	5
HPSI fluid temperature, °F	104
Charging system delay time, sec	150
Reactor scram low pressurizer pressure setpoint, psia	1807
Reactor scram delay time on low pressurizer pressure, sec	0.9
Scram CEA holding coil release delay time, sec	0.5
SIAS activation setpoint pressure for harsh conditions, psia	1520
HPSI pump delay time on SIAS, sec	30
MSSV lift pressures	Nominal + 3% uncertainty

Table 2.8.5.6.3-6
HPSI Flow Rate Versus RCS Pressure
(SBLOCA Analysis)

Cold Leg Pressure (psia)	Total Flow (to four loops) (gpm)	Total Flow to 3 Intact Loops (gpm)
15	616.3	455.7
315	531.3	392.9
615	424.4	313.8
815	339.8	251.2
1015	219.9	162.6
1115	119.5	87.5
1125	102.0	74.7
1135	66.4	48.6
1145	6.7	4.9
1145.5	0.0	0.0

Table 2.8.5.6.3-7
Summary of SBLOCA Break Spectrum Results

Break Area (ft^2)	0.04	0.05	0.06	0.07	0.08	0.09	0.10
PCT (°F)	1692	1643	2072(1)	1872	1724	1662	1619
Time of PCT (sec)	2681	2445	2166	2055	1772	1502	1305
Time of rupture (sec)	2383	2223	1661	1728	1612	1416	1259
Maximum local oxidation (%)	3.71	2.93	11.06	3.74	1.70	1.11	0.79
Percent total oxidation (%)	0.085	0.049	0.156	0.042	0.022	0.015	0.010
1. As shown in Table 2.8.5.6.3-8, one loop seal cleared for the 0.06 ft^2 break.							

Table 2.8.5.6.3-8
Sequence of Events
for SBLOCA Break Spectrum Calculations

Break Size (ft^2)	0.04	0.05	0.06	0.07	0.08	0.09	0.10
Time (sec)							
Event initiation (break in cold leg 2B)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pressurizer pressure reaches TM/LP setpoint (1807 psia)	29.36	23.47	19.63	16.93	14.96	13.48	12.35
Reactor trip, offsite power lost, RCPs tripped, MFW terminated, and turbine tripped	30.26	24.37	20.53	17.83	15.86	14.38	13.25
Pressurizer pressure reaches SIAS setpoint (1520 psia)	44.33	37.03	32.31	29.05	26.63	24.76	23.33
HPSI flow begins	198	168	146	128	114	102	92
SG level reaches AFAS setpoint (5.0% span)	175	151	135	121	246	248	250
Motor-driven AFW delivery begins	505	481	465	451	576	578	580
Loop seal 1A clears (biased loop)	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Loop seal 1B clears	668	528	440	388	334	292	260
Loop seal 2A clears	667	534	- - -	384	334	296	262
Loop seal 2B clears (biased loop) (broken loop)	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Break uncovers	700	565	465	405	348	305	275
Minimum RV mass occurs	2140	2064	1674	1694	1600	1428	1296
Hot rod rupture occurs	2383	2223	1661	1728	1612	1416	1259
SIT flow begins	- - -	- - -	2370	2050	1768	1498	1300
PCT occurs	2681	2445	2166	2055	1772	1502	1305

Table 2.8.5.6.3-9
Small Break LOCA Results and Comparison to Previous Results

Parameter	Criterion	EPU Analysis	Previous Analysis
PCT	≤ 2200 °F	2072°F	1765°F (excl. 50.46 assessments)
Maximum Local Cladding Oxidation	≤ 17%	11.06%	2.5%
Maximum Core-Wide Oxidation	≤ 1%	< 1%	< 1%
Coolable Geometry	Yes	Yes	Yes

Table 2.8.5.6.3-10
Plant Design Data
Used in the Boric Acid Precipitation Analysis

Parameter	Value
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
BAM tank parameters	
Maximum number of tanks	2
Maximum liquid volume per tank	9975 gal
Maximum boric acid concentration	6240 ppm
Minimum liquid temperature	51°F
RWT parameters	
Maximum volume	705,000 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	1202 ft^3
Maximum boric acid concentration	2600 ppm
Minimum liquid temperature	85.5°F
Maximum pressure	280 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	0 gpm
Minimum flow LPSI delivery	1962 gpm
Minimum containment spray pump flow rate	2750 gpm
RCS parameters	
Hot leg diameter	42 inches
Pump discharge leg diameter	30 inches
Pump suction leg diameter	30 inches

Table 2.8.5.6.3-10 (Continued)
Plant Design Data
Used in the Boric Acid Precipitation Analysis

Parameter	Value
Distance from bottom of loop seal to centerline of reactor vessel inlet nozzle	7.25 ft
Distance from bottom of discharge leg to bottom of active core	15.7 ft
Distance from the top of the active core to the bottom of the reactor vessel	21.58 ft
Distance from the top of the loop seals to the bottom of the reactor vessel	22.41 ft
Core flow area	54 ft^2
Guide tube flow area	6.34 ft^2
Core barrel/shroud bypass flow area	11.25 ft^2
Lower plenum volume	871.5 ft^3
Nominal RCS water mass	469,000 lbm
Mixing volume	7800 gal
RCP locked rotor K-factor for forward flow	13.39
1. The maximum RWT volume used in the analyses is conservative and bounds the actual maximum RWT volume.	

Table 2.8.5.6.3-11
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 w/o
Time boric acid concentration reaches solubility limit with no hot side injection	7 hours
Minimum simultaneous hot and cold side injection flow rates	
Hot Side	250 gpm
Cold Side	275 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 simultaneous hot and cold side injection started at 6 hours	26.6 w/o at 7.4 hours post-LOCA
Maximum core boric acid concentration with 20 gpm flushing flow Initiated at 6 hours	24.8 w/o at 6.0 hours post-LOCA
Current AOR	
CENPD-254-P-A Methodology	
Parameter	Current Result
Boric acid solubility limit	27.6 w/o
Time boric acid concentration reaches solubility limit with no hot side injection	12 hours
Minimum simultaneous hot and cold side injection flow rates	
Hot Side	190 gpm
Cold Side	235 gpm
Initiation time for simultaneous hot and cold side injection	4 to 10 hours post-LOCA
Maximum core boric acid concentration with 190 gpm of simultaneous hot and cold side injection started at 10 hours	25.1 w/o at 10.7 hours post-LOCA
Maximum core boric acid concentration with 20 gpm flushing flow Initiated at 10 hours	25 w/o at 10.0 hours post-LOCA

Figure 2.8.5.6.3-1
Small Break LOCA
Reactor Power

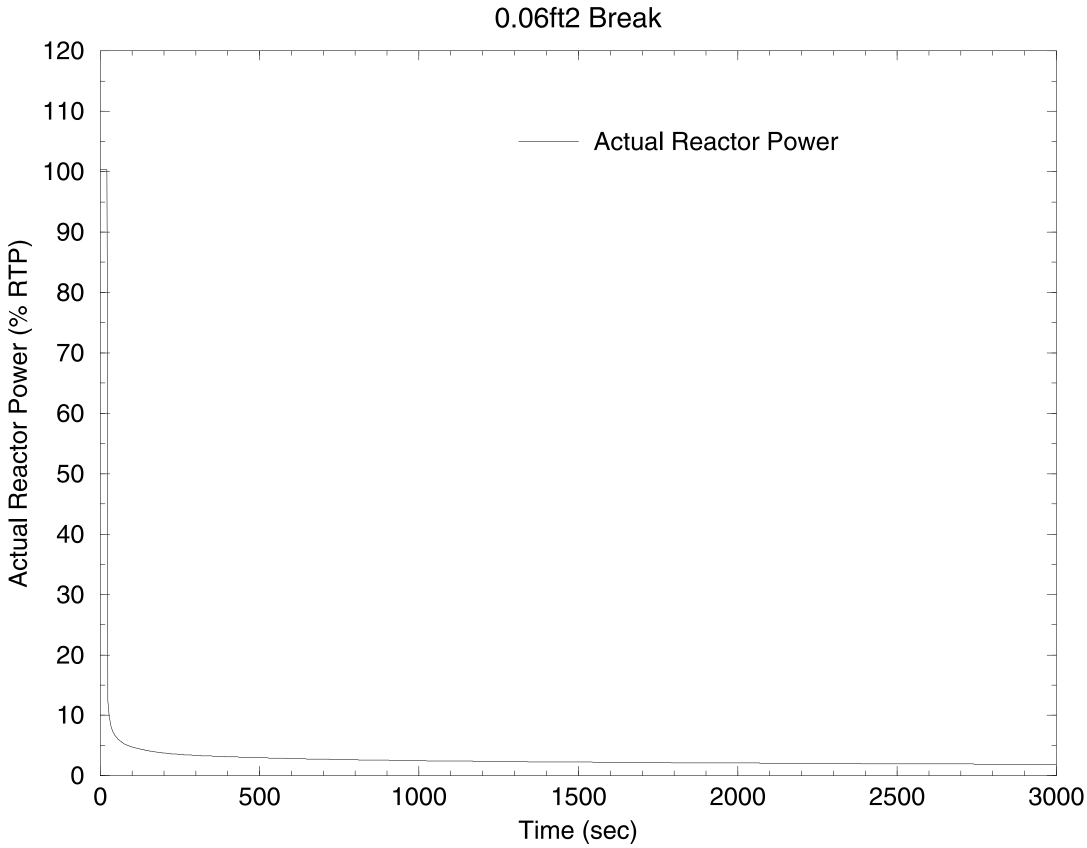


Figure 2.8.5.6.3-2
Small Break LOCA
Primary and Secondary Pressures

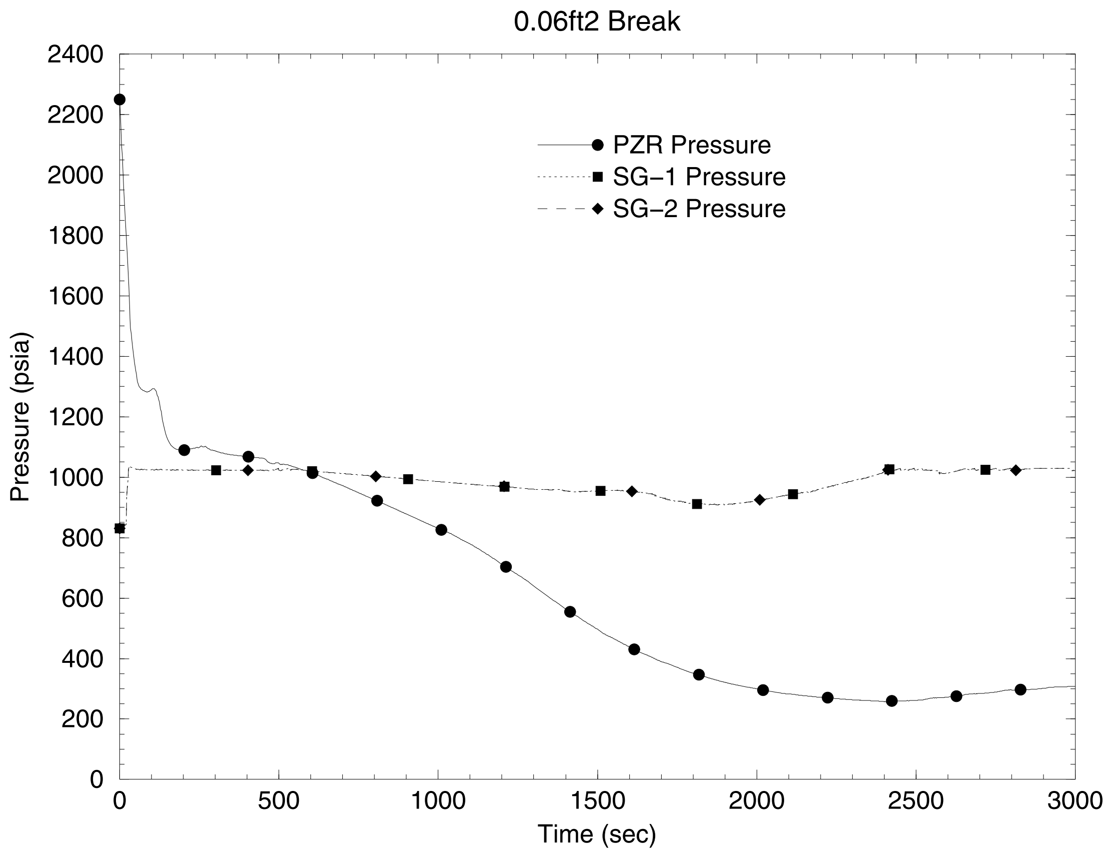


Figure 2.8.5.6.3-3
Small Break LOCA
Break Void Fraction

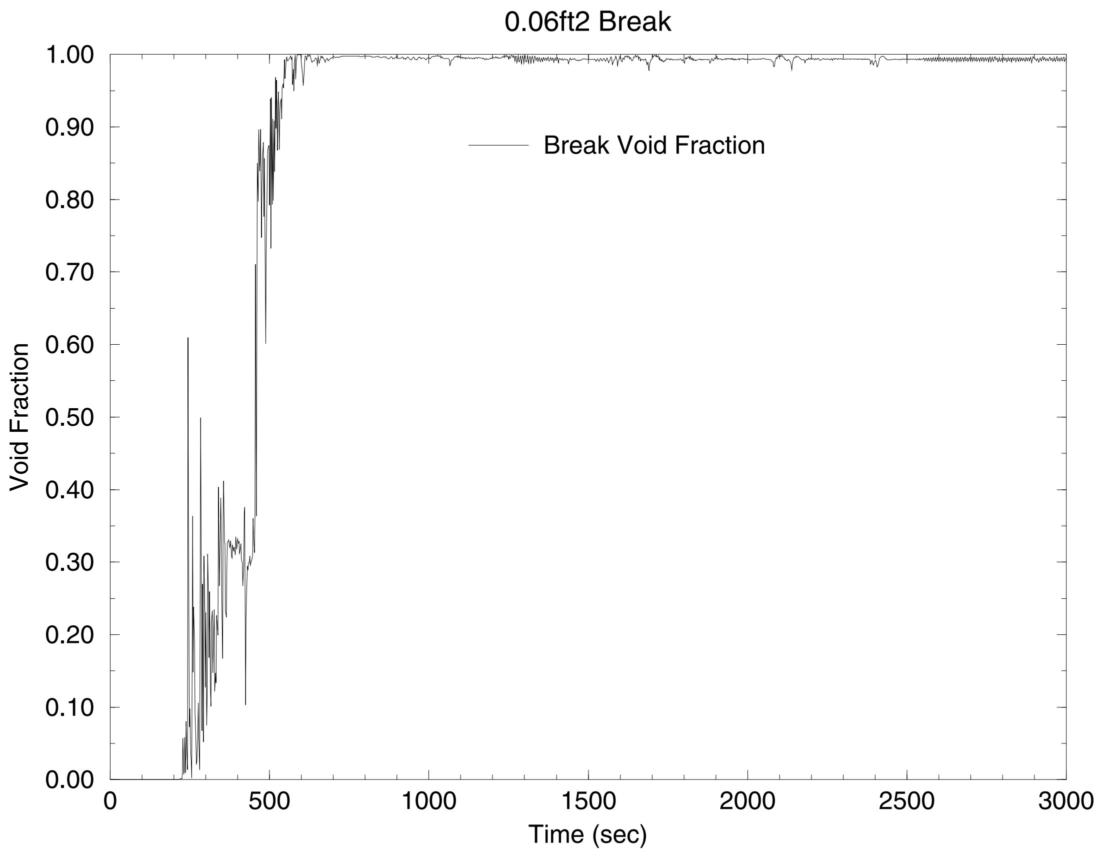


Figure 2.8.5.6.3-4
Small Break LOCA
Break Flow Rate

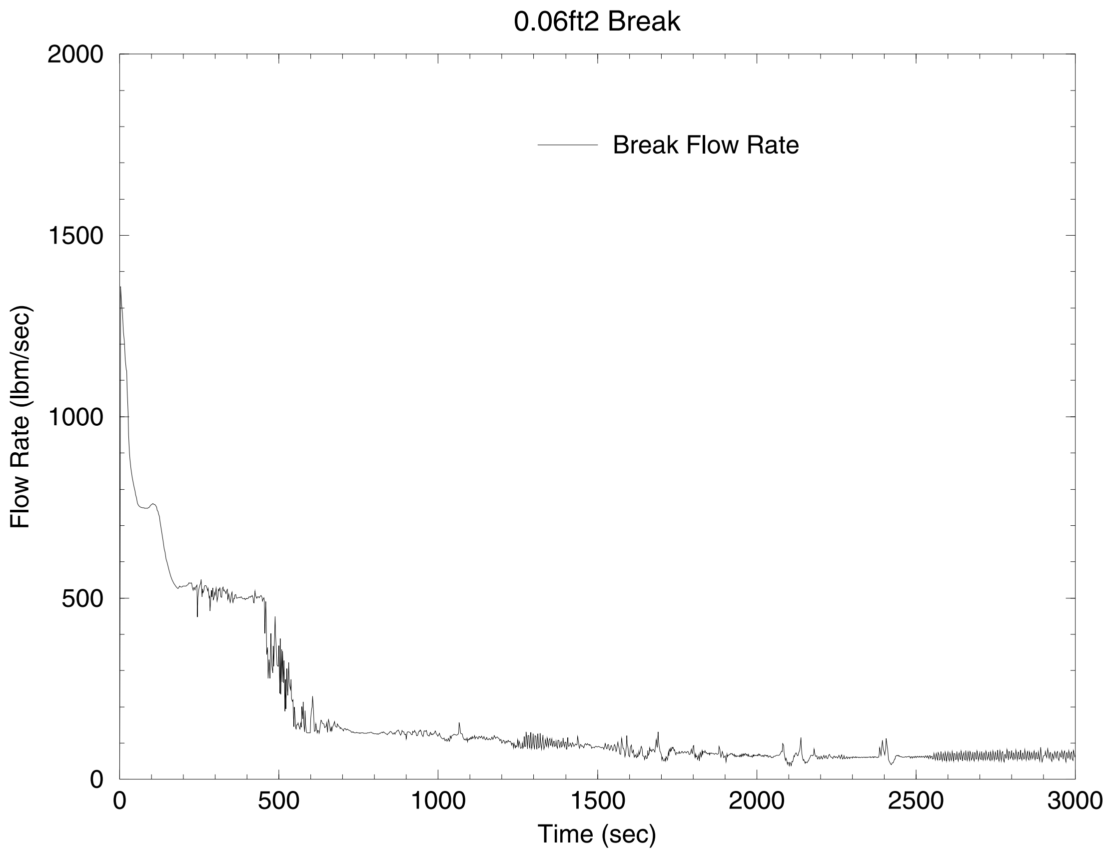


Figure 2.8.5.6.3-5
Small Break LOCA
Loop Seal Void Fractions

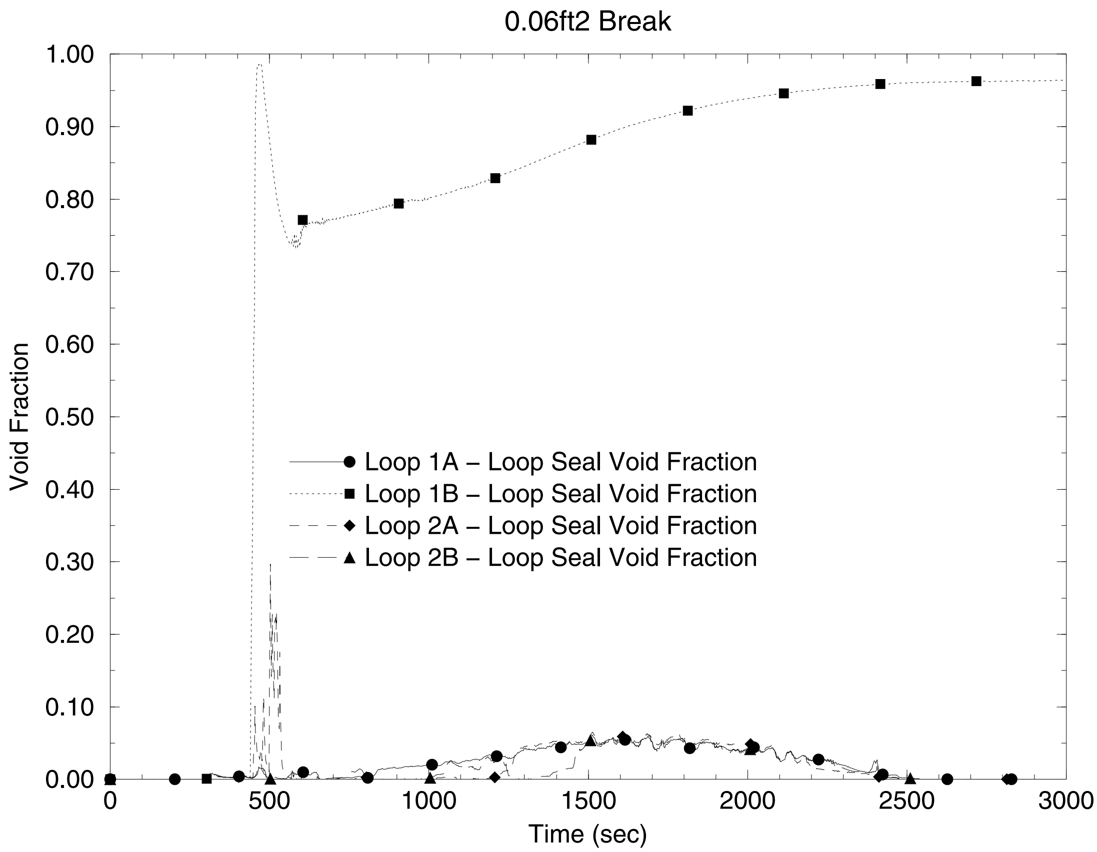


Figure 2.8.5.6.3-6
Small Break LOCA
RCS Loop Flow Rate

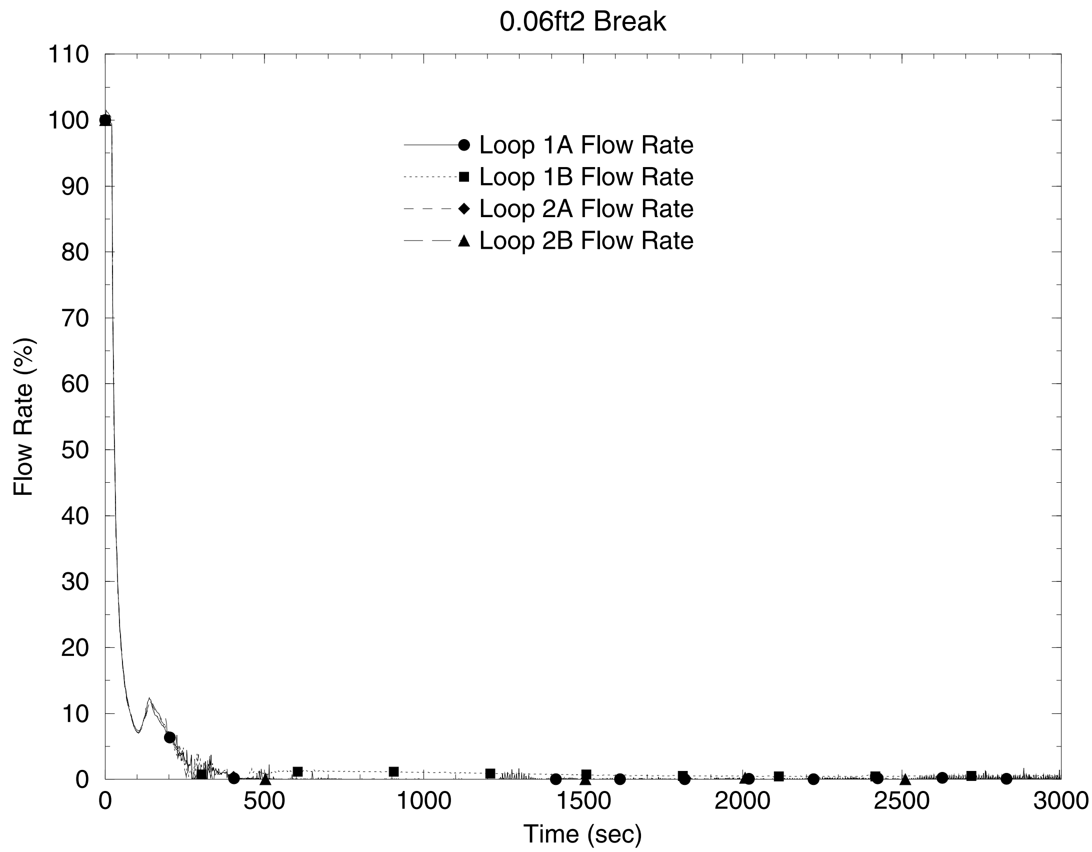


Figure 2.8.5.6.3-7
Small Break LOCA
MFW Flow Rate

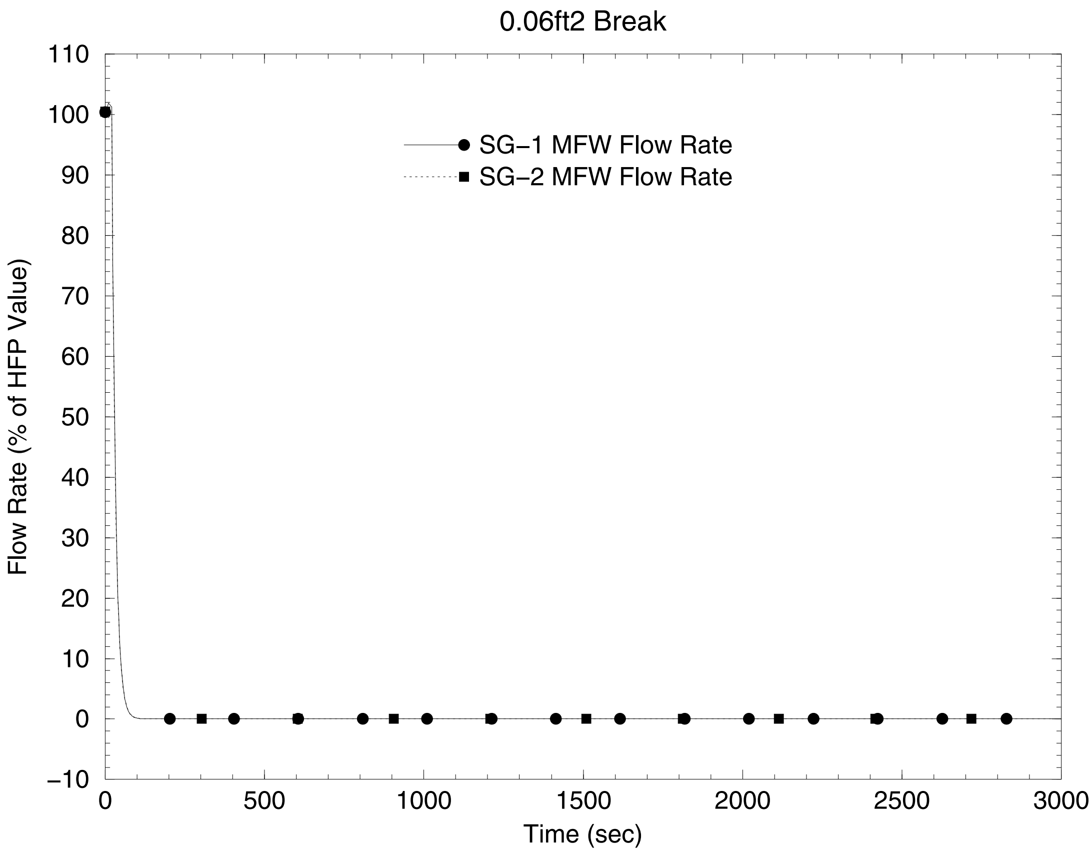


Figure 2.8.5.6.3-8
Small Break LOCA
AFW Flow Rate

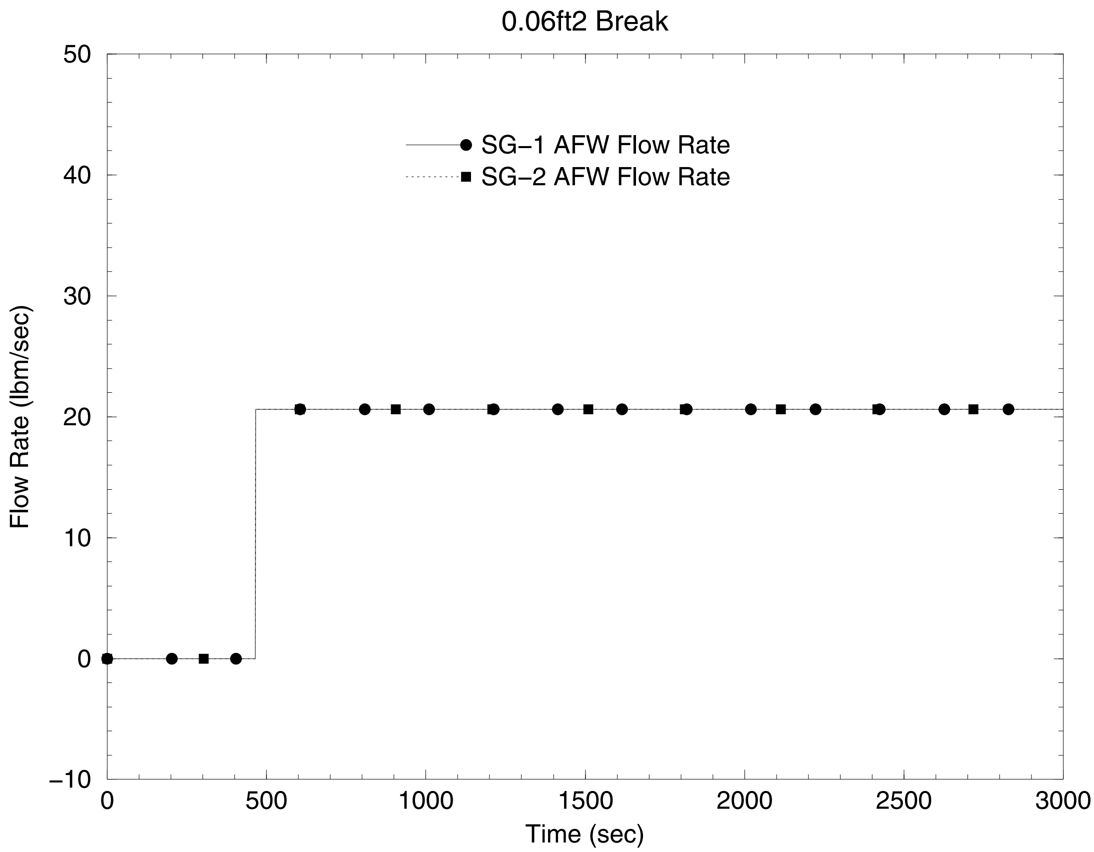


Figure 2.8.5.6.3-9
Small Break LOCA
Steam Generator Total Mass

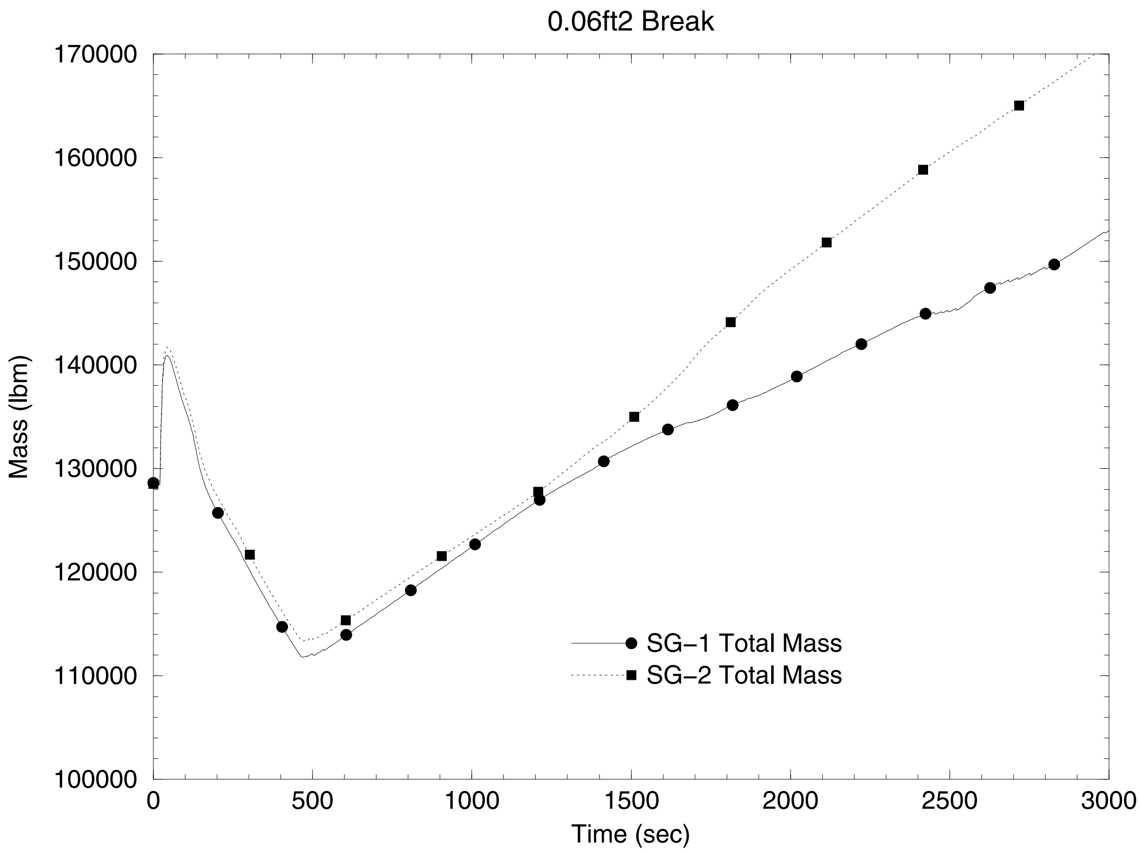


Figure 2.8.5.6.3-10
Small Break LOCA
Total HPSI Mass Flow Rate

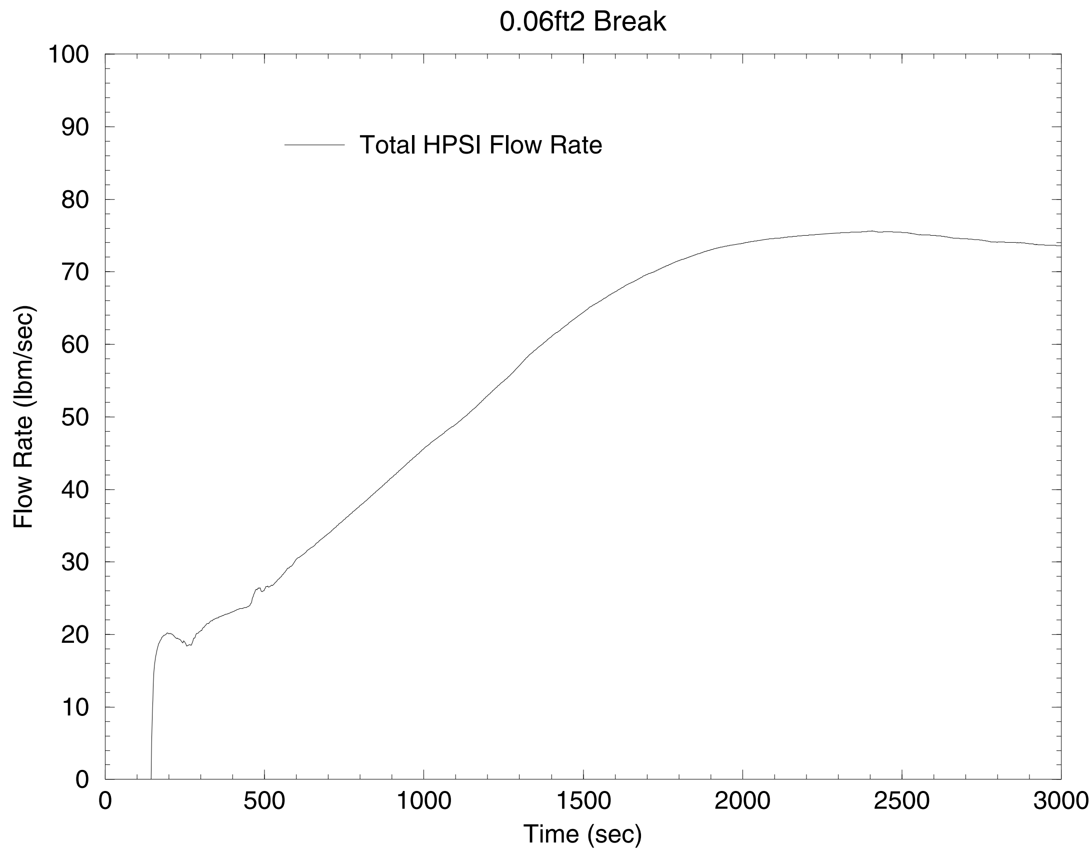


Figure 2.8.5.6.3-11
Small Break LOCA
RCS and Reactor Vessel Mass Inventories

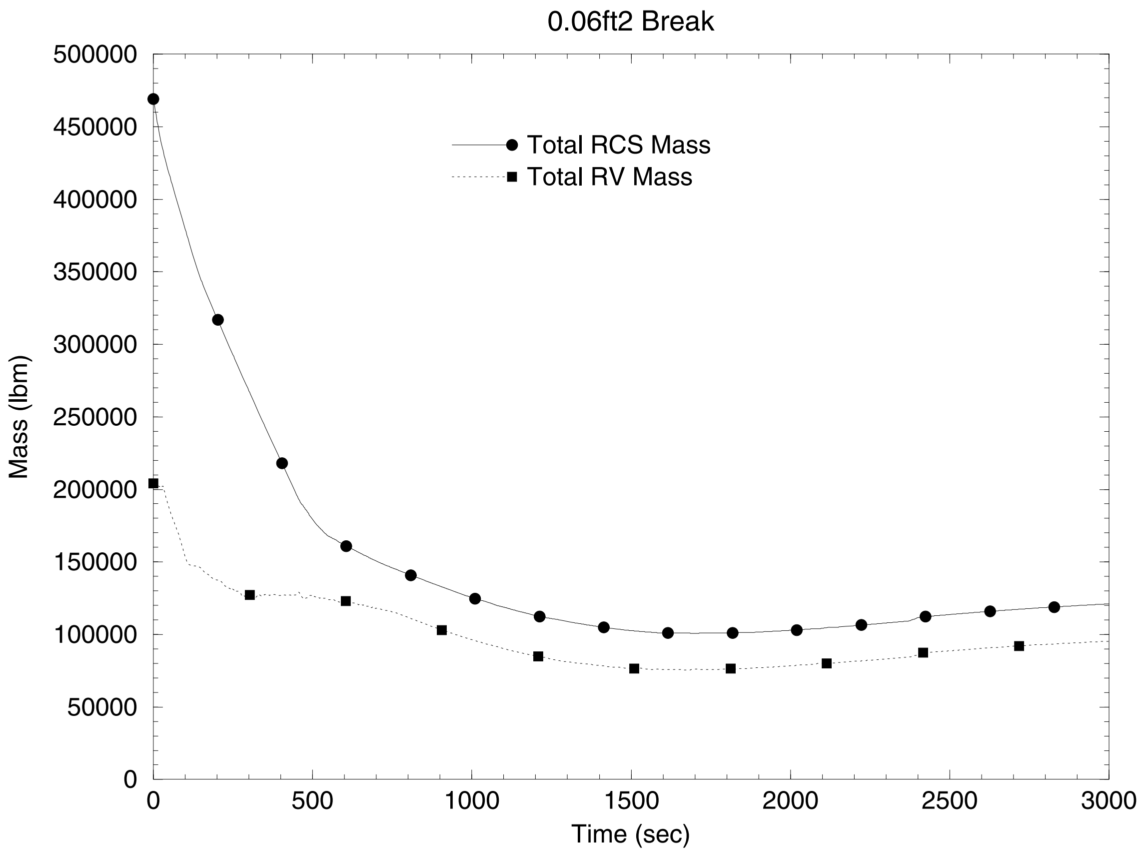


Figure 2.8.5.6.3-12
Small Break LOCA
Hot Assembly Collapsed Liquid Level

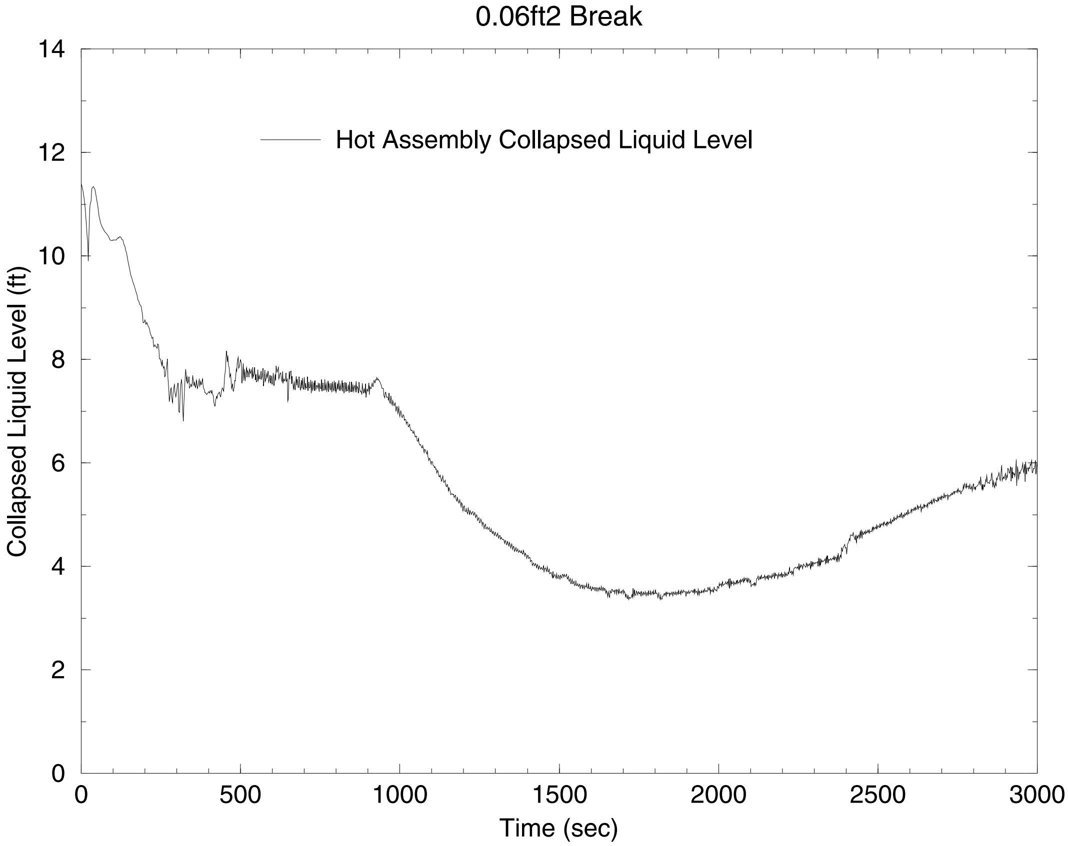


Figure 2.8.5.6.3-13
Small Break LOCA
Hot Spot Cladding Temperature

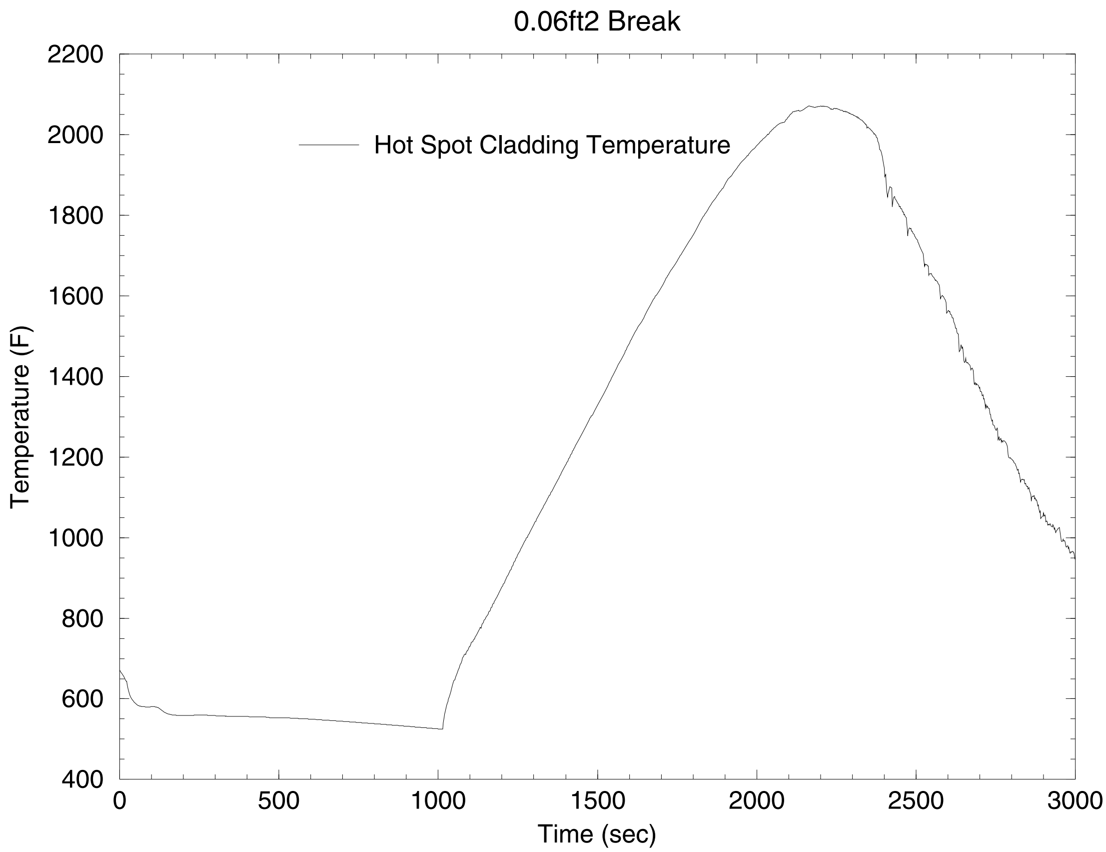


Figure 2.8.5.6.3-14
Boric Acid Concentration in the Core versus Time

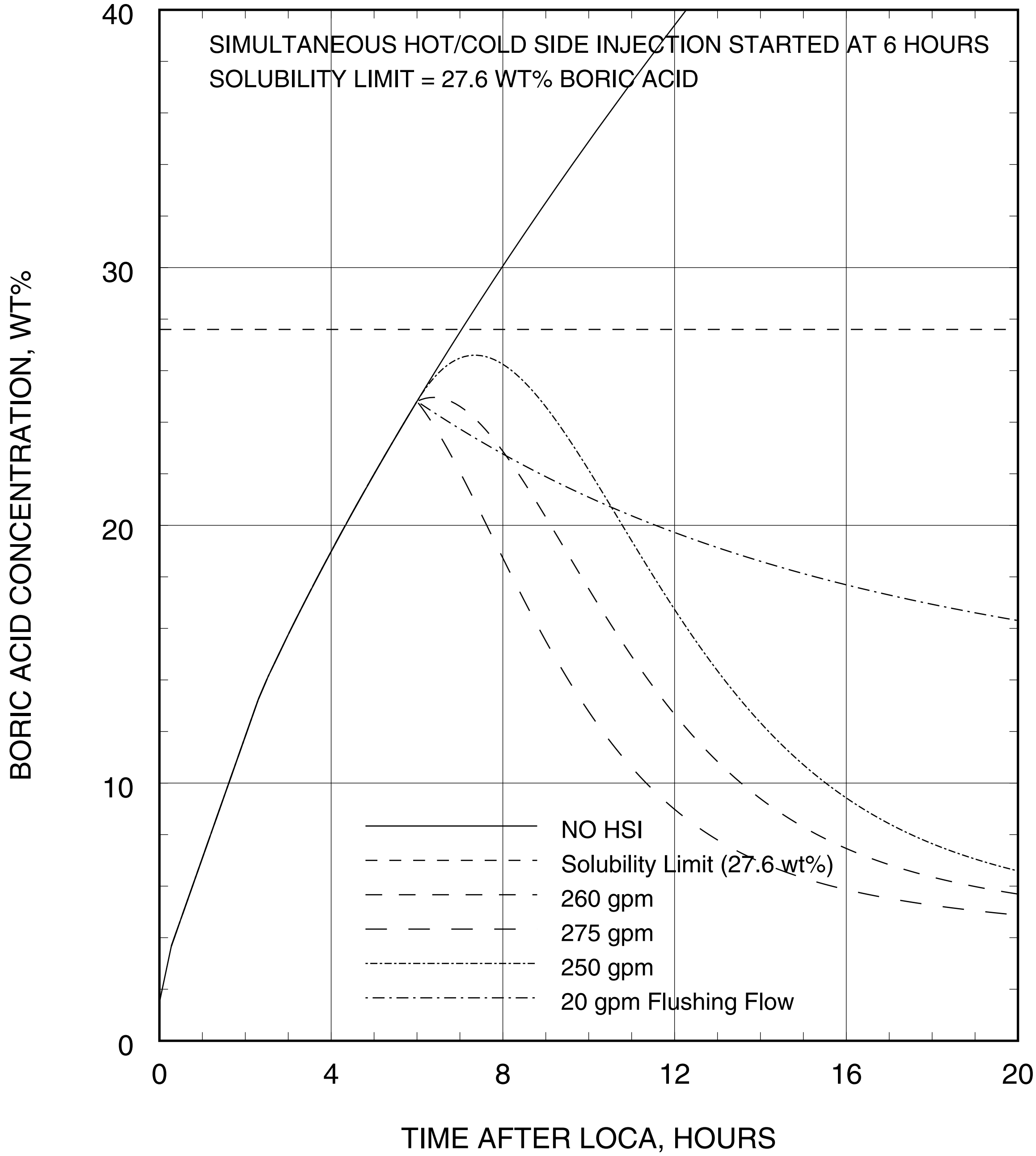
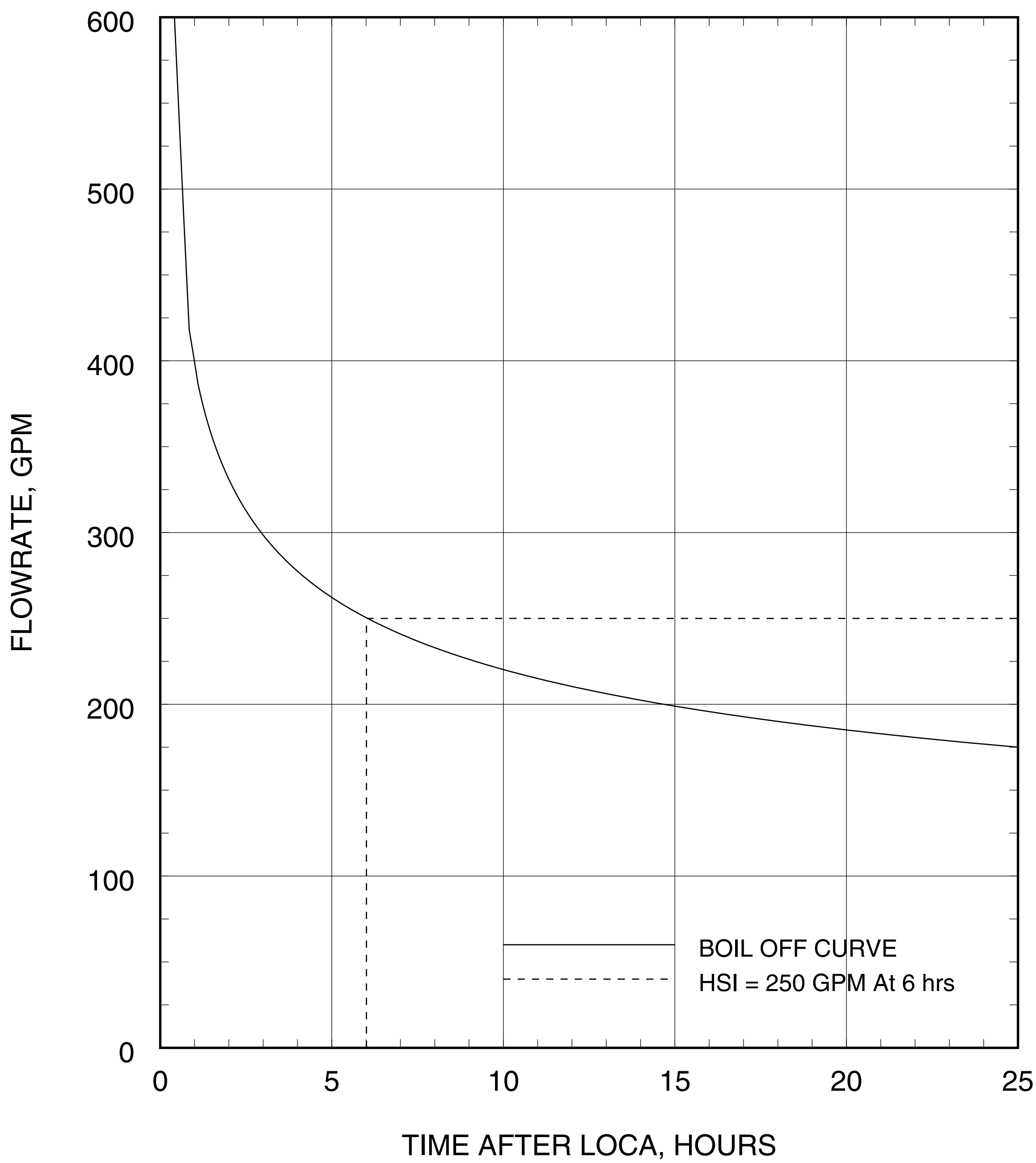


Figure 2.8.5.6.3-15
Core Boil-off and Simultaneous Hot/Cold Leg Injection versus Time



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 protection system specified in GDC-20. 10 CFR 50.62 requires that:

- Each 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 St. Lucie Unit 1 staff review was conducted to ensure that:

- The above requirements are met, and
- The setpoints for the diverse scram system (DSS), diverse turbine trip (DTT), and diverse auxiliary feedwater actuation system (DAFAS) remain valid for the proposed EPU. Note that since St. Lucie Unit 1 has a DSS, DTT, and a DAFAS, an ATWS event is not analyzed.

Specific review criteria are contained in guidance provided in Matrix 8 of RS-001, specifically Notes 7 and 10.

St. Lucie Unit 1 Current Licensing Basis

On July 26, 1984, The Code of Federal Regulations was amended to include 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 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 the 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 diverse scram system (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 to conserve steam generator 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 discussed in St. Lucie Unit 1 UFSAR Section 7.6.1.4.

St. Lucie Unit 1 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, St. Lucie Unit 1 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 auxiliary feedwater system. The DTT and DAFAS satisfy the ATWS rule requirements for mitigation.

The NRC has concluded that St. Lucie Unit 1's DSS, diverse turbine trip (DTT), and DAFAS designs was acceptable for compliance to 10 CFR 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 St. Lucie Unit 1 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.

The ATWS analysis is not within the scope of License Renewal.

2.8.5.7.2 Technical Evaluation

2.8.5.7.2.1 Introduction

As discussed in 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 auxiliary feedwater systems that is diverse from the RPS. Mitigation is accomplished by a diverse turbine trip (DTT) function and initiating a diverse auxiliary feedwater actuation system (DAFAS) to conserve steam generator 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 10CFR50.62 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 design improvements 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 a DTT is initiated, thereby tripping the turbine.

Diversity of the auxiliary feedwater actuation system 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 the DSS as discussed in St. Lucie Unit 1 UFSAR Section 7.6.1.4.1. The DAFAS, therefore, satisfied the ATWS Rule requirements for mitigation. The DAFAS does not have a separate setpoint for actuation; therefore the auxiliary feedwater actuation system (AFAS) setpoint on low steam generator level, as noted in Technical Specification Table 2.2-1 (Reference 3), applies.

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 1, which was manufactured by CE, has 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 St. Lucie Unit 1 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, DTT, or DAFAS designs, and therefore, these systems continue to comply with the ATWS Rule. Consistent with the respective Safety Evaluations approving these designs, the actuation setpoint for DSS/DTT remains above the reactor protection system 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 auxiliary feedwater actuation system. 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.

The ATWS analysis is not within the scope of License Renewal.

2.8.5.7.3 Results

The EPU does not modify the DSS, DTT, or DAFAS designs, and therefore, these systems continue to comply with the ATWS rule.

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 Systems, 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 setpoint is not impacted by the EPU, the existing setpoint for the DTT is not impacted by the EPU.

The diversity of the AFAS was approved based on the diversity of manufacturers and uses the low steam generator level setpoint for AFAS actuation. As stated in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, 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 analyzed for the St. Lucie Unit 1 EPU. For St. Lucie Unit 1, 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 its current licensing basis with respect to 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, 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), September 6, 1989.

3. St. Lucie Unit 1 Technical Specifications, through Amendment 204.

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 & 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:

- 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in FSAR Section 3.1.

The St. Lucie Unit 1 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 Section 9.1.1. New fuel assemblies are stored in racks in parallel rows having center-to-center distances of 21 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:

a. Store 80 fuel assemblies,

b. Provide sufficient spacing between the fuel assemblies to maintain a subcritical array during flooding with unborated water,

c. Maintain a subcritical array under design loadings, including the design basis earthquake,

d. Preclude the possibility of a fuel assembly being placed between the new fuel cavities,

e. 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}) occurs for a moderator void fraction of 0.91 and has a value of 0.974 at the 95% 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 bases described in the UFSAR, the new fuel storage was evaluated for St. Lucie Unit 1 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 will 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 for the following:

- The concrete walls of the vault are modeled as 100 cm thick, while in reality the wall thickness is as low as about 60 cm. This approach is conservative as it may increase the neutron reflection from the concrete.
- 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, water and the surrounding concrete.
- The wood 'floor' of the fuel storage rack is not credited and the fuel assemblies are assumed to be resting directly on the concrete floor. This is conservative as it may increase the neutron reflection from the floor.
- 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.
- 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.
- 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.

These criteria preclude the need to consider any second accident (per ANSI 8.1), or any accident under dry conditions.

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 0.0012 with an uncertainty of ± 0.0090 for MCNP4A, evaluated with a 95% probability at the 95% 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:

$$\text{Max } k_{eff} = \text{Calculated } k_{eff} + \text{bias} + [\Sigma_i \text{ (Uncertainty)}^2]^{1/2}$$

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% to 100% of the full water density. The uncertainty evaluations were performed for 100% 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 bases described in the UFSAR, the new fuel storage was evaluated for St. Lucie Unit 1 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% water density, including applicable uncertainties and applicable bias, is 0.9100. The optimum hypothetical low density moderation (i.e., fog or foam) occurs at 9% water density. The corresponding maximum calculated reactivity of the NFV for this 9% water density case, including applicable uncertainties and applicable bias, is 0.9767. 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 the 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 & 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:

- 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, 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 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDC. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDC.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in FSAR Section 3.1.

The specific GDCs 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 18 distinct modules of varying size in two regions. The cask pit rack is a Region 1 rack designed for storage of fresh or spent fuel assemblies having enrichments of up to 4.5 weight percent (w/o) U-235. Fuel assemblies are stored at a nominal 10.30-inch center-to-center spacing in the cask pit rack. Region 1 spent fuel pool storage racks are designed for storage of higher enriched irradiated fuel, with initial enrichments of up to 4.5 w/o U-235, such as might be temporarily discharged as part of a full core fuel offload. Region 1 is also designed to store fuel assemblies with enrichments up to 4.5 w/o U-235 that have not achieved sufficient burnup to be stored in Region 2. The center-to-center spacing in Region 1 is 10.12 inches. Region 2 storage cells were designed for fuel of various initial enrichments, including 4.5 w/o U-235 assemblies burned to at least 34.66 Mwd/KgU. The center-to-center spacing in this region is 8.86 inches. The spacing is sufficient to maintain the effective neutron multiplication factor (k_{eff}) less than 1.0 for all spent fuel assemblies when in unborated water.

UFSAR Section 9.1.2 states that the fuel pool is designed to provide safe storage for 1706 spent fuel assemblies, control element assemblies, new fuel during initial core loading and the spent fuel shipping cask. 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 $k_{eff} \leq 0.95$ is maintained, assuming credit for a portion of the soluble boron present in the fuel pool water and design basis earthquake (DBE) loading. The pool always contains boric acid at the refueling concentration of at least 1720 ppm whenever there is irradiated fuel in the pool.

In conjunction with the fuel pool storage racks, an additional rack (cask pit rack) is capable of being installed in the cask pit area of the spent fuel pool. The cask pit rack is removable and designed to provide storage for an additional 143 assemblies. This brings the total storage capability to 1849 assemblies with the cask pit rack installed. The cask pit rack is a Region 1 design capable of storing either fresh fuel or spent fuel regardless of burnup history. The cask pit rack is designed to maintain $k_{eff} \leq 0.95$ when the rack is fully loaded with fuel assemblies and flooded with unborated water.

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 spent fuel. Following issuance of the license amendment regarding spent fuel pool soluble boron credit, St. Lucie Unit 1 now credits the presence of soluble boron in fuel pool water during normal operating conditions, consistent with the requirements of 10 CFR 50.68(b)(4).

As originally fabricated, Region 1 and 2 rack modules contained a neutron absorber material, Boraflex, that is a silicone-based polymer containing fine particles of boron carbide in a homogenous matrix. Subsequent to the installation of rack modules containing this absorber material in the fuel pool, Boraflex was determined to be unsuitable for its intended application. Current fuel pool criticality analyses do not credit Boraflex as a neutron absorber or require that it be present in spent fuel storage racks.

For new fuel storage in spent fuel pool Region 2 racks, criticality analyses confirm that, subject to certain restrictions, fresh fuel assemblies enriched to 4.5 w/o U-235 may be placed in two of the three analyzed Region 2 storage arrays. To maintain an acceptably low value of k_{eff} when adding fresh fuel to Region 2, it is required that the four Region 2 cells face-adjacent to each fresh assembly be maintained water-filled, i.e., without fuel. Additionally, fresh fuel may not be placed in a cell diagonally adjacent to another fresh assembly. UFSAR Figure 9.1-22a provides pictorial guidance for the acceptable placement of fresh fuel in Region 2 racks.

UFSAR Section 9.1.2.3.5 associated with the criticality acceptance criteria states that: criticality is precluded by spacing of the fuel assemblies, and by burnup and post-irradiation cooling time requirements which ensure that a subcritical array is maintained, assuming unborated pool water. The pool, however, always contains boric acid at the refueling concentration of at least 1720 ppm whenever there is irradiated fuel in the pool. Considering the presence of soluble boron in the fuel pool at a concentration of at least 500 ppm, k_{eff} of the fuel pool will always be ≤ 0.95.

Analysis of inadvertent boron dilution events involving the spent fuel pool demonstrate that no credible dilution event can cause a reduction in boron concentration to less than 500 ppm.

UFSAR Section 9.1.2.3.2.1 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 $k_{eff} \leq 0.95$. A boron concentration of 1090 ppm is required to assure the regulatory limit of 0.95 for k_{eff} is not exceeded.

Via FPL letter to NRC L-2010-078 (Reference 1), FPL previously submitted an EPU License Amendment Request (LAR) for St. Lucie Unit 1. The LAR was subsequently withdrawn via FPL letter to NRC L-2010-181 (Reference 2). However, in response to NRC Reactor Systems Branch acceptance review questions, FPL made the following commitments related to fuel pool criticality (Reference 3; FPL letter to the NRC L-2010-162):

1. FPL commits to perform a new spent fuel pool criticality analysis to replace the existing analysis of record once the draft interim staff guidance (ISG) is formally issued. This revised analysis will be submitted as a separate license amendment request (LAR) for NRC review and approval. FPL will submit this LAR within one year of issuance of the final ISG.
2. Implement administrative controls to impose a 7% burnup penalty on the average burnup of any 2 X 2 array configuration allowed by current Technical Specifications. This burnup margin will offset the two issues identified by NRC and provides additional margin.
3. Implement administrative controls to maintain a SFP boron concentration limit of 2000 ppm which is above the current Technical Specification limit of 1720 ppm.
4. Verify the normal position of valve V15322 (primary makeup water hose connection to the cask storage isolation) is locked closed as part of normal operator rounds in the fuel handling building.
5. Verify, as part of normal operator rounds in the fuel handling building, that there are not other sources or indications of dilution to the SFP.
6. Verify that the SFP boron concentration is 2000 ppm twice every seven days.

In addition to the licensing bases described in the UFSAR, as modified by Reference 3, the spent fuel storage racks were evaluated for St. Lucie Unit 1 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 that components in the fuel handling building are within the scope of License Renewal. Programs used to manage the aging effects associated with the spent fuel storage racks are discussed in SER Section 3.5 and Chapter 18 of the UFSAR.

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 new EPU and existing pre-EPU fuel in the St. Lucie Unit 1 spent fuel pool. This criticality analysis completes commitment 1 made via the Reference 3 letter to the NRC described in the Current Licensing Basis subsection above. Since the criticality analysis does not require the administrative controls imposed by commitments 2-6 in the Reference 3 letter, these commitments will be discontinued upon implementation of the EPU criticality analysis following NRC approval of the EPU LAR.

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 fuel 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 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.

The effects of EPU on the spent fuel pool cooling system are evaluated in LR Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System.

2.8.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The calculations are performed with the same input parameters and assumptions that are used in the current licensing basis criticality analyses, except for the following:

- Spent Fuel Racks
  - Planar average enrichments up to 4.6 w/o U-235.
  - Bounding EPU core operating parameters for the depletion analyses: 900 ppm core soluble boron, reactor specific power of 36.59 MW/mtU, a conservative fuel temperature of 1727°F, and a peak power assembly exit moderator temperature of 630°F.
  - Revised pre-EPU core operating parameters: a conservative fuel temperature of 1627°F, and a peak power assembly exit moderator temperature of 620°F.
  - Credit for Metamic^{TM} DREAM inserts or Absorber Rods for additional reactivity control in some of the analyzed configurations.
- Cask Pit Racks (CPRs)
  - Fresh fuel planar average enrichment of 4.6 w/o U-235.

As in the current licensing basis criticality analyses, the objective of the spent fuel racks and cask pit racks 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% probability at a 95% confidence level.

See Sections 5 and 3 of HI-2104714, St. Lucie Unit 1 Criticality Analysis for EPU and Non-EPU Fuel, which is provided as part of Appendix I to Attachment 5 of the EPU LAR, for further details on input data and acceptance criteria of the analyses, respectively.

2.8.6.2.2.3 Description of Analyses and Evaluations

For the cask pit rack and the spent fuel racks, the following seven fuel configurations (cases) are analyzed:

Case 1: Cask Pit Rack uniformly loaded with fresh fuel;

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 Metamic^{TM} insert or one 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^{TM} insert or absorber rods in the fuel assemblies;

Case 6: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with any one of the four cells containing a Metamic^{TM} insert or absorber rods in any one of the fuel assemblies; and

Case 7: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with one empty location out of the four storage locations.

For each case with spent fuel (Cases 3 through 7), extensive calculations are performed to verify that, as a combined result of the revised operating parameters and the increased enrichment, and the additional neutron absorber (Cases 3, 5 and 6 only) the maximum reactivity is less than the allowed regulatory limit.

Additionally, for the spent fuel racks 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 243 critical experiments with fresh UO_2 fuel, fresh MOX fuel, and fuel with simulated actinide composition of spent fuel (HTC experiments). For details of the benchmarking analysis, see the MCNP Benchmark Calculations provided as part of Appendix I to Attachment 5 of the EPU LAR. The results of these benchmarking calculations show few significant trends, and indicate a bias of 0.0013 with an uncertainty of ± 0.0087, evaluated with a 95% probability at the 95% 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 1 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) using the following formula:

$$\text{Max } k_{eff} = \text{Calculated } k_{eff} + \text{biases} + [\Sigma_i (\text{Uncertainty})^2]^{1/2}$$

In the geometric models used for the calculations, full three-dimensional model 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 HI-2104714 (Appendix I to Attachment 5 of the EPU LAR), respectively.

Technical Specifications (TS) Figure 5.6-1, Allowable Region 1 Storage Patterns and Fuel Alignments and Figure 5.6-2, Allowable Region 2 Storage Patterns and Arrangements will be revised to address the new configurations (cases). TS Table 5.6-1 will be revised to specify the fuel enrichment and burnup requirements for all fuel, pre-EPU and EPU, with any axial enrichment profile. TS Table 5.6-2 will be deleted.

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™ insert, 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.

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 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.

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.

Since the required boron concentration of 500 ppm to maintain a $k_{eff} \leq 0.95$ is the same as previously required and the minimum Technical Specifications required boron concentration in the spent fuel pool will be increased from 1720 ppm to 1900 ppm, there is no adverse impact on the previously analyzed boron dilution event due to the implementation of EPU.

For the cask pit racks, the maximum k_{eff} is 0.9190, including biases and uncertainties, for flooding with non-borated water. This satisfies both applicable regulatory requirements, i.e., the k_{eff} limit of 0.95 for borated water, and the k_{eff} limit of 1.0 for non-borated water.

For further details about the results see Sections 7 and 9 of HI-2104714 (Appendix I to Attachment 5 of the EPU LAR).

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 bases 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
3. Neutron attenuation testing of Metamic™ coupons

1. <u>Visual Inspection</u>

   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 4) and Holtec International (Reference 5). 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^{TM} surfaces, only glass bead cleaning was used, as anodizing was extremely difficult due to the length of each chevron. Therefore, FPL proposes a visual inspection program to check for signs of corrosion pitting.

2. Physical Measurements

   Physical measurements of Metamic^{TM} inserts are used to confirm the stability of the dimensions of Metamic^{TM} material as noted in the testing (References 4 and 5). These measurements confirm the absence of swelling and shrinkage.

   Weight and physical dimensional measurements (length, width, and thickness) of Metamic^{TM} inserts will be performed at 4, 12, 20, and 30 years following initial installation of Metamic^{TM}.

3. Neutron Attenuation Testing

   Neutron attenuation testing is required to provide a periodic validation of certain assumptions embedded in the fuel pool rack's criticality analysis, and to also confirm that the neutron absorption capability of Metamic^{TM} would remain unchanged throughout its service lifetime. While this has been demonstrated through the earlier Metamic^{TM} 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^{TM} coupons will be performed at 4, 12, 20, and 30 years following initial installation of Metamic^{TM}.

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^{TM} 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^{TM} 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 temperature and 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. FPL letter to NRC L-2010-078, St. Lucie Plant Unit 1, License Amendment Request for Extended Power Uprate, April 16, 2010.
2. FPL Letter to NRC L-2010-181, St. Lucie Plant Unit 1, Withdrawal of Extended Power Uprate License Amendment Request, August 13, 2010.
3. FPL letter to NRC L-2010-162, St. Lucie Plant Unit 1, Extended Power Uprate License Amendment Request – Response to NRC Acceptance Review Questions, July 30, 2010.
4. EPRI 1003137, Qualification of METAMIC for Spent-Fuel Storage Application.
5. Holtec Report HI-2043215, Sourcebook for Metamic Performance Assessment, Revision 1 (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 during nonpower operation and the consequences of such a loss prompted NRC issuance of Generic Letter (GL) 88-17, Loss of Decay Heat Removal (Reference 1).

NRC GL 88-17, identified actions to be taken to preclude loss of decay heat removal during nonpower operations. These actions included operator training and the development of procedures and hardware modifications as necessary to prevent the loss of decay heat removal during reduced reactor coolant inventory operations, to mitigate accidents before they progress to core damage, and to control radioactive material if a core damage accident should occur. Procedures and administrative controls were required that cover reduced inventory operations and ensure that all hot legs are not blocked by nozzle dams unless a vent path is provided that is large enough to prevent pressurization and loss of water from the reactor vessel. Instrumentation was required to provide continuous core exit temperature and reactor water level indication. Sufficient equipment was required to be maintained in an operable or available status so as to mitigate the loss of 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 uncovery 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.
- 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 the St. Lucie Unit 1 UFSAR, Section 9.3.5.5.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

The adequacy of St. Lucie Unit 1 design and the actions taken in response to GL 88-17 are described in the St. Lucie Unit 1 UFSAR, Section 9.3.5.5. The following are specific actions taken by St. Lucie Unit 1 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 uncovery; (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 uncovery 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 generic letter.

FPL's commitments for St. Lucie Unit 1 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.

In addition to the licensing basis described in the UFSAR, the loss of decay heat removal at mid-loop operation analysis was evaluated for St. Lucie Unit 1 License Renewal and determined to be outside 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 in LR Section 2.8.7.1.1.

For St. Lucie Unit 1, “mid-loop” describes plant conditions in which fuel is in the reactor and the reactor vessel water level is below the top of the flow area of the RCS hot leg nozzles on the reactor vessel. This corresponds to a plant elevation of 31 ft, 3 in. Reduced inventory refers to conditions in which fuel is in the reactor and RCS water level is between 3 feet below the top of the reactor vessel flange and the top of the flow area of the RCS hot leg nozzles. The upper bound of reduced inventory water level corresponds to a plant elevation of 33 ft, 0 in.

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’s response to GL 88-17, procedural limitations are currently 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 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 uncovery:

   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, and after a certain point, a single charging pump could provide all the required makeup flow.

5. The performance of RCS time to boil, core uncovery, and vent area analyses to supplement design information and support procedures/instrumentation:

   FPL maintains analyses of the time to RCS boil, time to core uncovery, and required RCS vent area to preclude excessive pressurization. The analyses consider various initial conditions for RCS temperature, previous operating cycle length, RCS water volume, and time since shutdown. Results of the analyses support St. Lucie Unit 1 operating procedures in specifying the following:

   - Minimum required shutdown time prior to reduced inventory or mid-loop operation based on the available RCS vent area.
   - Required number of charging pumps as a function of time since shutdown.
   - Containment closure requirements based on the calculated RCS time to boil.
   - 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:

   St. Lucie Unit 1 minimizes perturbation-causing operations by the following procedural limitations:

   - Concurrent switchyard maintenance is restricted.
   - Concurrent maintenance and operations are prohibited on systems that could jeopardize the RCS, RCS makeup, SDC system, or support systems.
   - Access to the power block is restricted to only individuals who have been briefed on reduced inventory operations.
   - Two SDC loops are required to be operable in reduced inventory or mid-loop operations.
   - SDC flow and RCS draindown rates are procedurally limited to preclude low pressure safety injection (LPSI) pump failure due to insufficient net positive suction head, suction voiding, or air ingestion due to vortex formation.
   - A minimum RCS water level is maintained in part to preclude vortex formation in the partially filled RCS piping at the SDC suction line.

7. Controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously:

   Steam generator primary side manway and nozzle dam removal/installation are procedurally sequenced to prevent RCS pressurization and loss of inventory in the event that SDC becomes inoperable with fuel in the reactor vessel.

2.8.7.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

FPL calculates RCS time to boil, time to core uncovery, 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 results of the analyses provide the basis for the procedural limitations that ensure the licensing commitments relative to GL 88-17 can continue to 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 uncovery following a postulated loss of decay heat removal. Analyses have been performed to determine the new RCS time to boil and time to core uncovery. 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 EPU. Based on these reviews, the operating procedures will be revised to reflect the shorter times available to reach saturation and core uncovery and the impact this has on shutdown operations. FPL's commitments described in LR Section 2.8.7.1.2.1 are evaluated below to ensure EPU conditions will permit continued compliance.

2.8.7.1.2.4 Impact on 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.

2.8.7.1.2.5 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 the 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 impact the operability of the core exit thermocouples, refueling level indicators, or shutdown cooling temperature indication. Operating procedures 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 uncovery:

   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 depending on the 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 a commercial limitation and 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, St. Lucie Unit 1 has addressed the increased makeup water requirement for EPU and continues to be in compliance with this element of the GL 88-17 licensing commitments.

5. The performance of RCS time to boil, core uncovery, and vent area analyses to supplement design information and support procedures/ instrumentation:

   The increased decay heat generation following EPU impacts 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. Current analyses show that an unobstructed vent area of at least 0.56 ft^2 in the pressurizer manway foreign material exclusion cover provides sufficient steam flow to preclude pressurizing the reactor vessel to greater than 2.9 psig at 108 hrs after shutdown. If all eight seal carrier assemblies are removed from the reactor vessel head Quickloc flanges, the minimum shutdown time may be reduced to 72 hrs. 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 12 or fewer days. One charging pump is required beyond 12 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 12-day period.

   - Containment closure requirements based on the calculated RCS time to 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 maintenance has demonstrated that the hatch can be closed within the condition-specific calculated time to boil.

     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 account for 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 continues 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 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 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% 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.

  Consistent with the current analyses, the EPU analyses will not credit the steam generators as potential heat sinks. The procedural requirement to maintain 10% narrow range secondary water level will also be retained.

Given the results of these analyses, and the incorporation of their results into operating procedures, St. Lucie Unit 1 has adequately addressed the increased decay heat generation for EPU as it affects calculations supporting mid-loop and reduced inventory operations. St. Lucie Unit 1 continues to be in compliance with this element of the GL 88-17 licensing commitments.

6. Guidelines to ensure perturbation-causing operations are minimized:

   St. Lucie Unit 1 minimizes perturbation-causing operations 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 1 continues 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:

   St. Lucie Unit 1 sequences the installation and removal of manways and nozzle dams 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 1 continues to be in compliance with this element of the GL 88-17 licensing commitments.

2.8.7.1.3 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 1 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 continue to meet its current licensing bases with respect to 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.

2.8.7.1.4 References

1. NRC Generic Letter 88-17, Loss of Decay Heat Removal, October 17, 1988.
2. Letter from W.F. Conway (FPL), to NRC, Loss of Decay Heat Removal, 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), July 21, 1990.
4. Letter from D.A. Sager (FPL), to NRC, Programmed Enhancements for Generic Letter 88-17," July 25, 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, 9, 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	
RCS Heatup Volume	ft^3	1437	/	1437	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	1144	/	1144	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 uncovery	psig	2.9	/	2.9	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 at mid-loop:	
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 uncovery' calculation covers conditions where RCS pressure may remain higher than 15 psia.
5	Density variation in the RCS due to temperature changes is not credited in the 'time to core uncovery' calculations. This assumption has an insignificant effect on calculated results.
Assumptions for time to boil above mid-loop:	
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% 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	12/17*	*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	108/156*	*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	72/96*	*estimated based on pre-EPU vs. EPU decay heat calculation results
Time to core boil at 72 hrs/96 hrs (pre-EPU/EPU) after shutdown	Minutes	12.5/12.5*	72 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 (SRP) or other guidance documentation for EPU license basis reviews for natural circulation cooldown. For the EPU, an evaluation is performed that shows the acceptability of natural circulation cooldown performance at EPU conditions.

While there are no explicit criteria for this evaluation, the following criteria to show acceptable natural circulation cooldown behavior:

- The natural circulation ΔTs and temperatures are bounded by full-power conditions. This helps to avoid any concerns with thermal stresses and helps to ensure adequate reactor coolant system (RCS) subcooling.
- The RCS pressure is reduced to 275 psia for shutdown cooling (SDC) 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.
- Availability of adequate condensate supply necessary to achieve natural circulation cooldown conditions.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 a result of this event the NRC staff in a letter dated July 8, 1980 (Reference 6) requested that FPL provide certain specific information which is summarized in part in the following.

1. Provide analyses of plant cooldown on natural circulation using an analytical model that properly accounts for relatively stagnant fluid in the upper head of the vessel and the metal structure.
2. Provide discussions of the consequences of a more severe depressurization.
3. Evaluate consequences of the seals failing on all four reactor coolant pumps.

4. Provide the results of a review of the events analyzed in UFSAR Chapter 15 relative to upper head fluid conditions.

5. Describe how operator guidelines and procedures have been revised.

6. Perform modeling of the cooldown on the simulator for operator training.

The NRCs evaluation of FPL's response to the above is captured in a Safety Evaluation Report (SER) transmitted in a letter from Robert A. Clark, (NRC), *Natural Circulation Cooldown,* to Dr. Robert E. Uhrig, (FPL), dated April 26, 1983 (Reference 4). The NRC notes in the Natural Circulation Cooldown SER that the SER did not include a review of guidelines and procedures that will ultimately be reviewed as part of NUREG-0737 TMI Action Item I.C.1 and that FPL should review its programs to assure and confirm that the following items have been addressed.

a. How voiding occurs and its consequences

b. Signs that voiding is occurring

c. Discussions of procedures to prevent and mitigate voiding

d. Discussion of the St. Lucie Unit 1 event of June 11, 1980

e. Proper simulator modeling of upper head voiding

The NRC SER concludes in part that upper head voiding, in itself, does not present any safety concerns provided that the operator has adequate training and procedures to recognize and react to the situation. The NRC conclusion is based upon analyses presented in CEN-199, Effects of Vessel Head Voiding During Transients and Accidents in CE NSSS's, dated March 1982 (Reference 5). Furthermore, the requirement to review guidelines and procedures as specified in the SER has been performed as presented in Letter L-83-382 from Robert E. Uhrig (FPL), Natural Circulation Cooldown, to Robert A. Clark (NRC), dated June 30, 1983 (Reference 7).

Additional information pertaining to natural circulation cooldown is presented in UFSAR Appendix 5C.

Rapid refill and drain of the reactor vessel head during natural circulation cooldown is discussed in UFSAR Section 5.4.2.

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 EPU conditions exhibits expected natural circulation behavior, similar to that previously analyzed. The evaluation demonstrates the ability to cool down the plant on natural circulation to SDC entry conditions (< 275 psia, and less than 325°F in the RCS) within a reasonable period of time.

The current analysis described in Reference 1 was performed by FPL in December 1980 in response to the June 11, 1980 event which resulted in steam formation within the upper head of the reactor vessel. The current 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 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 volume, required for this cooldown 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 Section 1.1, Nuclear Steam Supply System Parameters with the exception of cooldown rates which are 30°F/hr and 50°F/hr.

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 one (1) hour before initiating the natural circulation cooldown.
- Decay heat rates are based on ANSI/ANS-5.1-1979.
- Maximum initial feedwater enthalpy is assumed until the feedwater piping is purged. Maximum auxiliary feedwater enthalpy corresponding to maximum condensate storage tank temperature, 120°F, is assumed after the feedwater piping is purged.

Acceptance Criteria

There are no formal acceptance criteria for this EPU evaluation. The guidelines of NRC Branch Technical Position (BTP) 5-4 (Reference 2) are used to show that the system is capable of bringing the reactor to SDC entry conditions, with loss of offsite power, within a reasonable period of time following shutdown.

While there are no explicit criteria for this evaluation, the following criteria show acceptable natural circulation cooldown behavior:

- The natural circulation ΔTs 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.
- The RCS pressure is reduced to 275 psia for SDC 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.
- 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 the EPU, the CENTS computer code was used to simulate the plant response to a loss of offsite power followed by a natural circulation cooldown from hot standby conditions to shutdown cooling system entry conditions. The CENTS code is not a part of the CLB, but is a NRC approved code that is acceptable for referencing in licensing applications for Combustion Engineering designed pressurized water reactors (Reference 3).

Consistent with the UFSAR, Appendix 5C, two separate scenarios were simulated. A case with a cooldown rate of 30°F/hour and a case with a cooldown rate of 50°F/hour and conservative assumptions. After one (1) hour 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 volume requirement were compared to the current values. The EPU results and the current bounding case results are shown in LR Table 2.8.7.2-1.

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 EPU evaluation demonstrates that the plant can be cooled down to SDC 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 EPU conditions will not adversely impact the natural circulation cooldown capability of the plant for the following reasons:

- 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.
- The RCS pressure is reduced to 275 psia for SDC initiation and the upper head fluid is cooled to a value less than the corresponding saturation temperature of 409.5°F.
- The current condensate volume requirement established in the current evaluation is bounding for the EPU.

This analysis shows:

- Acceptable results were determined for natural circulation cooling during the hot standby period for expected residual heat rates immediately following reactor shutdown from the EPU conditions.
- The atmospheric dump valves at the EPU conditions are adequate to achieve cooldown to the SDC entry point in a reasonable time period. Shutdown cooling entry conditions can be

achieved in less than 13 hours at a cooldown rate of either 30°F/hr or 50°F/hr, which includes one (1) hour in hot standby.

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. However, the analysis assumes that the operators do not depressurize below the reactor vessel upper head saturation pressure to preclude drawing a void in the head. This means that the cooldown rate of the upper head fluid governs the time required to reach shutdown cooling entry conditions. The EPU analysis results are lower than the current analysis due to the use of a more sophisticated analysis code which does not require soak time.

2.8.7.2.3 Conclusion

FPL has reviewed the analyses related to natural circulation cooldown and concludes that the analyses have adequately accounted for the effects of changes in plant conditions. FPL 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, St. Lucie Unit 1 will continue to meet its current licensing basis 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, January 20, 1981.

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. Letter from Robert A. Clark, NRC, Safety Evaluation Report Natural Circulation Cooldown, to Dr. Robert E. Uhrig, FPL, April 26, 1983.

5. CEN-199, Effects of Vessel Head Voiding During Transients and Accidents in CE NSSS's, March 1982.

6. Letter from T. Novak to R.E. Uhrig (FPL), Cooldown on Natural Circulation, Information Request, July 8, 1980.

7. Letter L-83-382 from Robert E. Uhrig (FPL), Natural Circulation Cooldown, to Robert A. Clark (NRC), June 30, 1983.

Table 2.8.7.2-1
Calculated Loop ΔT, Cooldown Time, and Condensate Volume Requirement for Natural Circulation

Analysis	Cooldown Rate (°F/hr)	Maximum Calculated Loop ΔT (°F)	Time to Shutdown Cooling Entry (hr)	Condensate Requirement (gallons)
Pre-EPU	50°F/hr	-	25.7	270,500
EPU	30°F/hr	28	12.5	177,000
EPU	50°F/hr	34	11.0	170,000
The condensate inventory required for the EPU conditions would be 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 code which does not require a soak time.				

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

2.9.1.1 Regulatory Evaluation

FPL reviewed the radioactive source term associated with the 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 reasonably achievable” 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 SRP Section 11.1, and guidance provided in Matrix 9 of RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the general design criteria is discussed in the UFSAR Section 3.1.

Specifically, the adequacy of the radioactive source term is determined for the 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 10 CFR 50 Appendix I for normal operations and for any transient situation that might reasonably be anticipated to occur.

The licensing basis annual radiation doses to the maximum individual from liquid and gaseous pathways are presented in UFSAR Tables 11.2-15 and 11.3-6, respectively. The licensing basis annual radiation doses are below the design objectives of 10 CFR 50, Appendix I.

The licensing basis radioactivity concentrations in the liquid discharge are determined using models and assumptions contained in NUREG-0017. The total inventory released from the liquid waste system following treatment is presented in UFSAR Table 11.2-14 for the normal and anticipated conditions. Liquid releases for the normal and anticipated nuclide concentrations in the circulating water discharge system are also listed in UFSAR Table 11.2-14. The licensing basis annual radiation doses to the maximum individual from liquid pathways are presented in UFSAR Table 11.2-15. The licensing basis annual radiation doses are below the design objectives of 10 CFR 50, Appendix I.

UFSAR Sections 11.3.2 and 11.3.6 discusses the key parameters utilized to determine the radioactive source term for gaseous effluents. UFSAR Table 11.3-4 gives the estimated radioactive isotopic release rates via gaseous effluents from each release point. The licensing basis annual radiation doses to the maximum individual from gaseous pathways are presented in UFSAR Table 11.3-6. The licensing basis annual radiation doses are below the design objectives of 10 CFR 50, Appendix I.

The information regarding the licensing basis annual releases and radiation doses due to liquid and gaseous effluents is retained in the UFSAR Sections 11.2 and 11.3 to avoid loss of the original design basis.

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 1 and associated doses to the public are reported annually to the NRC in the Annual Radioactive Effluent Release Report. This report serves to demonstrate continued compliance with the regulatory limits.

In addition to the licensing bases described in the UFSAR, the waste management system was evaluated for St. Lucie Unit 1 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 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 steam generator 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 1 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 Terms (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 percent 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 percent 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 at St. Lucie Unit 1. 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 on offsite doses is discussed in LR Section 2.10.1, Occupational and Public Radiation Doses.

2.9.1.3 Conclusion

FPL has reviewed the radioactive source term associated with the 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 386,354[(1)]	ft^3 lbs
Volume control tank (VCT) pressure	15	psig
VCT temperature	120	^oF
Letdown flow rate[(2)]	40.0	gpm
Mixed bed demineralizer decontamination factors	2 for cesium 10 for all other isotopes except Y, Mo and noble gases	N/A
Lithium removal mixed bed demineralizer use and equivalent flow rate	Inservice 20% of the time (neglected for corrosion product determination) 8	 gpm
Lithium removal mixed bed demineralizer decontamination factors	2 for Cesium 10 for all other isotopes except Y, Mo and noble gases	N/A
Cation demineralizer flow rate	N/A	gpm
Primary makeup water (boron recovery flow)	200,000	gallons/year
Depleted zinc injection considered?	Yes	N/A

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 Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (µCi/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 (Continued)
RCS Source Term

Nuclide	Half-Life (sec)	Core Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results: Equilibrium Concentration (µCi/gm)	Results: 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
SB129	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
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

Table 2.9.1-3 (Continued)
RCS Source Term

Nuclide	Half-Life (sec)	Core Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (µCi/gm)	Equilibrium Activity (µCi)
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
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	-	-

Table 2.9.1-3 (Continued)
RCS Source Term

Nuclide	Half-Life (sec)	Core Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (µCi/gm)	Equilibrium Activity (µCi)
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
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

Table 2.9.1-3 (Continued)
RCS Source Term

Nuclide	Half-Life (sec)	Core Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (μCi/gm)	Equilibrium Activity (μCi)
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	-	-
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

Table 2.9.1-3 (Continued)
RCS Source Term

Nuclide	Half-Life (sec)	Core Activity (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (µCi/gm)	Equilibrium Activity (µCi)
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	-	-
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	-	-

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

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
- Inadvertent opening of a main steam safety valve (IOMSSV)

The St. Lucie Unit 1 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;
- 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;
- Regulatory Guide 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) General Design Criteria (GDCs). In preparation for issuance of the St. Lucie Unit 1 Updated Final Safety Analysis Report (UFSAR), an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in FSAR Section 3.1.

The current licensing basis 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 November 26, 2008, the NRC approved Amendment 206 to the St. Lucie Unit 1 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 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% 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 μCi/gm Dose Equivalent (DE) I-131. The non-iodine species are adjusted to achieve a proposed TS limit of 518.9 μCi/gm DE Xe-133 using effective air submersion dose conversion factors (DCFs) from Table III.1 of Federal Guidance Report 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 ≤ 0.10 μCi/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 μCi/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 1 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 10 high burnup assemblies (versus 8 high burnup assemblies), a high burnup adjustment/increase of 4.608% 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% 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 MSLB, 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. Figure 2.9.2-1 provides a sketch of the general layout of St. Lucie Unit 1 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) for Analysis Events – 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 Section 2.7.1, Control Room Habitability System and Section 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 following two exceptions:

1. The volume of the control room envelope that is serviced by the control room ventilation system is increased to 96,228 ft^3 to include the net free volume of the technical support center, which is an integral part of the control room HVAC envelope. A sensitivity analysis indicated that the larger volume for the control room did not significantly impact dose results (<1%).
2. 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% 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 Section 6.2.3.1 of the UFSAR, the initial leakage rate from containment is 0.5% of the containment volume per day. Per RG 1.183, Regulatory Position 3.7, the primary containment leakage rate is reduced by 50% at 24 hours into the LOCA to 0.25%/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 4510 cc/hr, based upon two times the current licensing basis value of 2255 cc/hr. The leakage is conservatively assumed to start at 24 minutes into the event and continue throughout the 30-day period. This portion of the analysis assumes that 10% of the total iodine is released from the leaked liquid. The form of the released iodine is 97% elemental iodine and 3% 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 minutes into the event when recirculation starts and continue throughout the 30-day 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 4.05E-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 4.962 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 0.1735 (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% 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 µCi/gm DE I-131 and 518.9 µCi/gm DE Xe-133 gross activity) is available for release via this pathway. The release is modeled for 30 seconds at 500 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 as a ground level release prior to drawdown of the secondary containment at 310 seconds. Activity subsequently collected by the shield building ventilation system (SBVS) is assumed to be a filtered release from the plant stack with a filter efficiency of 99% for particulates and 95% for both elemental iodine and organic iodine. The activity that bypasses the SBVS is released unfiltered to the environment via a ground level release from containment. 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% and elemental iodine and organic iodine efficiencies of 95%. 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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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 86% 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 2.33 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 6.43 hr^{-1}, the DF of 50 is conservatively computed to occur at 2.302 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:

- Core radionuclide inventory consistent with EPU conditions
- 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
- Operating conditions for hydrogen purge versus containment purge
- 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

2.9.2.3.4 Results

The post-accident doses are the result of five distinct activity releases:

1. Containment leakage via the secondary containment system.
2. Containment leakage bypassing the secondary containment.
3. ESF system leakage into the RAB.
4. ESF system leakage into the RWT.
5. Hydrogen purge at event initiation.

The dose to the control room occupants includes terms for:

1. Contamination of the control room atmosphere by intake and infiltration of radioactive material from the containment and ESF.
2. External radioactive plume shine contribution from the containment and ESF leakage releases. This term takes credit for control room structural shielding.
3. A direct shine dose contribution from the containment's contained accident activity. This term takes credit for both containment and control room structural shielding.
4. 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% 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% 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% elemental iodine and 0.15% 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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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 change is:

- 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 4.608%), 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 μCi/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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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
- 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 μCi/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.

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 μCi/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 920 cfm of unfiltered fresh air and an assumed value of 500 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 472.7 seconds. A 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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 2.9.2-21 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
- 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% 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 4.608%) 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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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 and 2.9.2-29. 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
- 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% of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere. The second case assumes that 100% 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 2.9.2-30, including a comparison to the inputs utilized in References 1 and 2. The postulated accident consists of two cases. One case assumes that 100% of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere, and the second case assumes that 100% 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% 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 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 μCi/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% of the fuel experiences FCM and 9.5% 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 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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% 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 2.9.2-30 and 2.9.2-31. 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
- 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 IOMSSV Radiological Consequences

2.9.2.9.1 Description of Event

This event is caused by an inadvertent opening of a SG MSSV. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products contained in the primary coolant before the accident are discharged from the primary into the secondary system. The analysis assumes that the SG tubes become uncovered and therefore no credit is taken for scrubbing in the SG or any credit for a flashing fraction for the primary leakage into the SGs. As a result, all of the leaked RCS radioactivity is released to the outside atmosphere from the secondary coolant system through the SG via the MSSVs. In addition, all of the activity initially present in the SGs is assumed to be released to the environment over a 2-hour period. Radiological releases due to the opening of a power operated atmospheric dump valve are bounded by the IOMSSV event.

2.9.2.9.2 Analysis Parameters and Assumptions

Inputs and assumptions for the IOMSSV are documented in LR Table 2.9.2-32, 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 in the RCS tube leakage is released directly to the environment until terminated at 12.4 hours. In addition, the entire secondary side activity is released to the environment over a 2-hour period.

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 920 cfm of unfiltered fresh air and an assumed value of 500 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 50-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, 500 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, 500 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% for particulates, 95% for elemental iodine, and 95% for organic iodine.

2.9.2.9.3 Comparison to References 1 and 2

The analysis of the IOMSSV 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 2.9.2-32 and 2.9.2-33. 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
- 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 DBA IOMSSV 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 IOMSSV dose calculations, and the applicable dose acceptance criteria, are presented in LR Table 2.9.2-1.

2.9.2.10 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.

2.9.2.11 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 10 CFR 50.67, 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.

2.9.2.12 References

1. L-2007-085, Letter from Florida Power & Light Company to the USNRC, St. Lucie Unit 1, Docket No. 50-335, 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 1 – Issuance of Amendment Regarding Alternative Source Term (TAC No. MD6173), November 26, 2008.
3. L-2008-022, Letter from Florida Power & Light Company to the USNRC, 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, 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, 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, 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, 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, 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	500	0.91	2.05	4.83	4.69
MSLB – Outside of Containment (1.3% DNB)	500	0.23	0.68	4.66	4.80
MSLB – Outside of Containment (0.32% FCM)	500	0.27	0.73	4.82	4.97
MSLB – Inside of Containment (21% DNB)	500	0.33	0.72	4.80	4.92
MSLB – Inside of Containment (5.0% FCM)	500	0.55	1.02	4.66	4.91
SGTR Pre-accident Iodine Spike	500	0.30	0.30	4.69	3.03
Acceptance Criteria		**≤ 25(3)**	**≤ 25(3)**	**≤ 5(4)**	**≤ 5(4)**
SGTR Concurrent Iodine Spike	500	0.15	0.22	2.29	0.60
Locked Rotor (19% DNB)	500	0.30	0.71	4.60	2.53
IOMSSV(5)	500	0.02	0.03	0.40	0.30
Acceptance Criteria		**≤ 2.5 (3)**	**≤ 2.5 (3)**	**≤ 5 (4)**	**≤ 5 (4)**
FHA - Containment	500	0.45	0.44	1.51	1.23
FHA – Fuel Handling Building	500	0.45	0.44	3.90	3.02
CEA Ejection – Containment Release (9.5% DNB, 0.5% FCM)	500	0.22	0.45	3.43	2.74

Table 2.9.2-1 (Continued)
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)	500	0.26	0.58	3.41	2.60
Acceptance Criteria		**≤ 6.3**[3]	**≤ 6.3**[3]	**≤ 5**[4]	**≤ 5**[4]

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 (Continued)
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	μCi/gm
I-131	8.425E-02
I-132	1.689E-02
I-133	8.713E-02
I-134	7.73E-03
I-135	3.933E-02

Table 2.9.2-4
LOCA Containment Leakage Source Term

Nuclide	EPU Source Core/Fuel Source (Curies)	Pre-EPU Source from Reference 1 Core/Fuel Source (Curies)	% Difference
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 (Continued)
LOCA Containment Leakage Source Term

Nuclide	EPU Source Core/Fuel Source (Curies)	Pre-EPU Source from Reference 1 Core/Fuel Source (Curies)	% Difference
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 (Continued)
LOCA Containment Leakage Source Term

Nuclide	EPU Source Core/Fuel Source (Curies)	Pre-EPU Source from Reference 1 Core/Fuel Source (Curies)	% Difference
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 (Continued)
LOCA Containment Leakage Source Term

Nuclide	EPU Source Core/Fuel Source (Curies)	Pre-EPU Source from Reference 1 Core/Fuel Source (Curies)	% Difference
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
A positive % difference indicates that the EPU source inventory is higher than the pre-EPU source inventory. EPU evaluated a wider range of enrichments.			

Table 2.9.2-5
Fuel Handling Accident Source Term

Nuclide	Activity (Curies)		Nuclide	Activity (Curies)		Nuclide	Activity (Curies)
Co-58	0.000E+00		Xe-135	3.341E+05		Te-125m	3.911E+03
Co-60	0.000E+00		Cs-134	2.536E+05		Te-133m	4.424E+05
Kr-85	9.417E+03		Cs-136	6.227E+04		Ba-141	9.918E+05
Kr-85m	1.508E+05		Cs-137	1.052E+05		Ba-137m	9.973E+04
Kr-87	2.864E+05		Ba-139	1.094E+06		Pd-109	4.216E+05
Kr-88	4.026E+05		Ba-140	1.054E+06		Rh-106	7.574E+05
Rb-86	2.142E+03		La-140	1.101E+06		Rh-103m	1.081E+06
Sr-89	5.521E+05		La-141	9.966E+05		Tc-101	1.117E+06
Sr-90	7.554E+04		La-142	9.600E+05		Eu-154	1.586E+04
Sr-91	6.856E+05		Ce-141	1.014E+06		Eu-155	1.100E+04
Sr-92	7.494E+05		Ce-143	9.179E+05		Eu-156	3.622E+05
Y-90	7.880E+04		Ce-144	8.526E+05		La-143	9.110E+05
Y-91	7.212E+05		Pr-143	9.128E+05		Nb-97	1.021E+06
Y-92	7.531E+05		Nd-147	4.023E+05		Nb-95m	7.268E+03
Y-93	8.804E+05		Np-239	1.851E+07		Pm-147	9.215E+04
Zr-95	1.016E+06		Pu-238	4.719E+03		Pm-148	1.879E+05
Zr-97	1.011E+06		Pu-239	2.911E+02		Pm-149	4.224E+05
Nb-95	1.028E+06		Pu-240	5.480E+02		Pm-151	1.544E+05
Mo-99	1.202E+06		Pu-241	1.357E+05		Pm-148m	2.259E+04
Tc-99m	1.052E+06		Am-241	1.532E+02		Pr-144	8.583E+05
Ru-103	1.200E+06		Cm-242	6.798E+04		Pr-144m	1.024E+04
Ru-105	9.714E+05		Cm-244	2.488E+04		Sm-153	5.158E+05
Ru-106	6.909E+05		I-130	5.275E+04		Y-94	8.931E+05
Rh-105	8.747E+05		Kr-83m	7.273E+04		Y-95	9.671E+05
Sb-127	8.842E+04		Xe-138	1.004E+06		Y-91m	3.980E+05
Sb-129	2.399E+05		Xe-131m	7.470E+03		Br-82	5.881E+03
Te-127	8.796E+04		Xe-133m	4.074E+04		Br-83	7.247E+04
Te-127m	1.200E+04		Xe-135m	2.671E+05		Br-84	1.241E+05
Te-129	2.361E+05		Cs-138	1.117E+06		Am-242	9.393E+04
Te-129m	3.503E+04		Cs-134m	5.683E+04		Np-238	5.019E+05
Te-131m	1.012E+05		Rb-88	4.100E+05		Pu-243	8.717E+05
Te-132	9.227E+05		Rb-89	5.234E+05		-----	-----

Table 2.9.2-5 (Continued)
Fuel Handling Accident Source Term

Nuclide	Activity (Curies)		Nuclide	Activity (Curies)		Nuclide	Activity (Curies)
I-131	6.654E+05		Sb-124	2.681E+03			
I-132	9.425E+05		Sb-125	1.767E+04			
I-133	1.255E+06		Sb-126	1.359E+03			
I-134	1.358E+06		Te-131	5.853E+05			
I-135	1.183E+06		Te-133	7.486E+05			
Xe-133	1.260E+06		Te-134	9.973E+05			

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	18.2	38.6	354
Stack/Plant Vent	Midpoint between CR intakes	56.1	18.2	22.8	8
RWT	N CR intake	14.6	18.2	74.7	65
RWT	S CR intake	14.6	18.2	80.3	39
RWT	Midpoint between CR intakes	14.6	18.2	74.6	52
FHB Closest Point	N CR intake	13.2	18.2	36.7	48
FHB Closest Point	S CR intake	13.2	18.2	56.1	11
FHB Closest Point	Midpoint between CR intakes	13.2	18.2	43.3	25
Louver L-7B	N CR intake	11.6	18.2	37.7	72
Louver L-7B	S CR intake	11.6	18.2	46.5	24
Louver L-7B	Midpoint between CR intakes	11.6	18.2	37.6	45
Louver L-7A	N CR intake	11.6	18.2	40.3	83
Louver L-7A	S CR intake	11.6	18.2	41.7	34
Louver L-7A	Midpoint between CR intakes	11.6	18.2	36.1	59
Closest ADV	N CR intake	16.1	18.2	32.2	306
Closest ADV	S CR intake	16.1	18.2	65.4	319
Closest ADV	Midpoint between CR intakes	16.1	18.2	48.8	314
Closest Main Steam Line Point	N CR intake	5.2	18.2	31.5	303
Closest Main Steam Line Point	S CR intake	5.2	18.2	64.4	318
Closest Main Steam Line Point	Midpoint between CR intakes	5.2	18.2	47.9	312
Closest Feedwater Line Point	N CR intake	5.2	18.2	25.3	306
Closest Feedwater Line Point	S CR intake	5.2	18.2	58.8	321

Table 2.9.2-6 (Continued)
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 Feedwater Line Point	Midpoint between CR intakes	5.2	18.2	42.1	315
Containment Maintenance Hatch	N CR intake	4.9	18.2	52.5	359
Containment Maintenance Hatch	S CR intake	4.9	18.2	85.0	348
Containment Maintenance Hatch	Midpoint between CR intakes	4.9	18.2	68.1	351
Steam Jet Air Ejector	N CR intake	16.0	18.2	45.6	266
Steam Jet Air Ejector	S CR intake	16.0	18.2	63.5	296

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. Other release/receptor pairs (such as pairs J and K below) that may have qualified for different wind sector credits were conservatively considered to be in the same wind sector for these EPU analyses.
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.

Table 2.9.2-7
Onsite Atmospheric Dispersion Factors (X/Q) for Analysis Events

This table summarizes the X/Q values (sec/m3) 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 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.

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				
			1.70%				
B*	Stack/Plant Vent	S CR intake	6.95E-04	4.95E-04	2.17E-04	1.54E-04	1.19E-04
			4.12%	8.79%	2.97%	22.31%	28.11%
C	Stack/Plant Vent	Midpoint between CR intakes	3.92E-03				
			3.70%				
D	RWT	N CR intake	1.38E-03				
			0.00%				
E	RWT	S CR intake	1.17E-03	9.36E-04	4.10E-04	3.09E-04	2.15E-04
			6.36%	0.65%	3.54%	5.10%	-5.70%
F	RWT	Midpoint between CR intakes	1.37E-03				
			3.01%				
G	FHB Closest Point	N CR intake	5.14E-03				
			4.26%				
H	FHB Closest Point	S CR intake	2.06E-03	1.55E-03	6.72E-04	4.86E-04	3.29E-04
			7.36%	8.33%	7.27%	25.84%	8.42%
I	FHB Closest Point	Midpoint between CR intakes	3.50E-03				
			-0.82%				

Table 2.9.2-7 (Continued)
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
J	Louver L-7B	N CR intake	4.81E-03				
			4.20%				
K	Louver L-7A	S CR intake	3.79E-03	3.03E-03	1.33E-03	9.88E-04	6.83E-04
			1.59%	-0.93%	-1.63%	-6.10%	-13.79%
L	Louver L-7A	Midpoint between CR intakes	5.12E-03				
			3.07%				
M#	Closest ADV	N CR intake	6.05E-03	4.81E-03	1.79E-03	1.53E-03	1.22E-03
			0.00%	5.69%	5.92%	13.13%	23.51%
N#	Closest ADV	S CR intake	1.58E-03	1.30E-03	5.19E-04	4.05E-04	3.31E-04
			0.36%	5.74%	7.67%	11.54%	25.61%
O#	Closest ADV	Midpoint between CR intakes	2.75E-03				
			-2.41%				
P	Closest Main Steam Line Point	N CR intake	5.00E-03				
			-2.53%				
Q	Closest Main Steam Line Point	S CR intake	1.46E-03	1.17E-03	4.80E-04	3.70E-04	2.97E-04
			-2.01%	2.63%	0.84%	10.78%	19.28%
R	Closest Main Steam Line Point	Midpoint between CR intakes	2.45E-03				
			-2.00%				
S	Closest Feedwater Line Point	N CR intake	7.11E-03				
			-2.60%				
T	Closest Feedwater Line Point	S CR intake	1.72E-03	1.40E-03	5.84E-04	4.50E-04	3.57E-04
			-2.60%	0.36%	0.46%	6.63%	17.36%
U	Closest Feedwater Line Point	Midpoint between CR intakes	3.10E-03				
			-2.21%				
V	Containment Maintenance Hatch	N CR intake	1.90E-03				
			1.60%				
W	Containment Maintenance Hatch	S CR intake	8.15E-04	6.49E-04	2.88E-04	2.03E-04	1.65E-04
			0.49%	6.22%	3.23%	18.02%	28.91%

Table 2.9.2-7 (Continued)
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
X	Containment Maintenance Hatch	Midpoint between CR intakes	1.21E-03				
			1.68%				
Y	Steam Jet Air Ejector (1)	N CR intake	2.97E-03				
			20.2%				

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)	S	U	T
ECCS Leakage	J	L	K
RWT Backleakage	D	F	E
Cont. Purge/H_2 Purge	A	C	B
FHA:			
Containment Release	V	X	W
FHB Release	G	I	H
MSLB:			
Outside Containment – Intact SG	M	O	N
Outside Containment – Faulted SG	P	R	Q
Inside Containment (SBVS)	A	C	B
Inside Containment (SBVS Bypass)	S	U	T
SGTR	Y (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)	S	U	T
IOMSSV	M	O	N

Table 2.9.2-9
Offsite Atmospheric Dispersion Factors (X/Q) for Analysis Events

Time Period	EAB *X/Q* (sec/m^3)	LPZ *X/Q* (sec/m^3)
0–2 hours	7.96E-05	7.70E-05
0–8 hours	4.56E-05	4.38E-05
8–24 hours	3.45E-05	3.30E-05
1–4 days	1.91E-05	1.81E-05
4–30 days	8.46E-06	7.97E-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	96,228 ft^3	62,318 ft^3
Normal Operation		
Filtered Makeup Flow Rate	0 cfm	Same
Filtered Recirculation Flow Rate	0 cfm	Same
Unfiltered Makeup Flow Rate	920 cfm	Same
Unfiltered Inleakage	500 cfm	Same
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
Unfiltered Inleakage	500 cfm	Same
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
Unfiltered Inleakage	500 cfm	Same
Filter Efficiencies:		
Particulates	99%	Same
Elemental iodine	95%	Same
Organic iodine	95%	Same

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	0.03
Filters	0.09
External Cloud	0.08
Total	0.20

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 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 μCi/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	0.5% (by volume)/day	Same
after 24 hours	0.25% (by volume)/day	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 (Continued)
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
ECCS Systems Leakage		
Sump Volume (minimum)	67,268 ft^3	55,460 ft^3 (difference based on thermodynamic conditions and delivered RWT inventory)
ECCS Leakage to RAB (2 times allowed value)	4510 cc/hr	Same
Flashing Fraction	Calculated – 5.5% Used for dose determination – 10%	Calculated – 7.5% 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
RWT Back-leakage		
Sump Volume (at time of recirculation)	67,268 ft^3	57,140 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)	45,084 gallons	38,842 gallons

Table 2.9.2-12 (Continued)
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Release from Sump to RWT Vapor Space	Table 2.9.2-17	Different based on RWT/sump conditions
Release from RWT Vapor Space to Environment	1.06 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	500 cfm for 30 sec (H_2 purge)	42,000 cfm for 5 sec (cont purge)
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
Containment Spray Region Volume	2,155,160 ft^3	Same
Containment Unsprayed Region Volume	350,840 ft^3	Same
Flow rate between sprayed and unsprayed containment volumes	23,389 cfm (during spray operation, equal to 4 x unsprayed volume per hour) 11,695 cfm (after sprays are secured, equal to 2 x unsprayed volume per hour)	11,695 cfm
Spray Removal Rates:		
Elemental Iodine	20/hour	Same
Time to reach DF of 200	2.33 hours	3.02 hours
Particulate Iodine	6.43/hour	Same
Time to reach DF of 50	2.302 hours	2.60 hours

Table 2.9.2-12 (Continued)
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Spray Initiation Time Spray Termination Time	64.5 seconds (0.017917 hours) 8 hours	Same 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) 50 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
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

Table 2.9.2-12 (Continued)
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Personnel Dose Conversion Inputs:		
Atmospheric Dispersion Factors		
Offsite	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	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
0.40	4.500
0.50	4.500
1.0	4.501
5.0	4.505
10.0	4.511
15.0	4.517
25.0	4.527
50.0	4.554
75.0	4.578
100.0	4.602
125.0	4.624
150.0	4.645
200.0	4.684
250.0	4.720
300.0	4.754
350.0	4.784
400.0	4.813
450.0	4.840
500.0	4.865
550.0	4.889
600.0	4.912
650.0	4.934
700.0	4.954
720.0	4.962

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 $[I_2]$aq (gm-atom/liter)
0.00	0.00E+00	0
0.40	0.00E+00	0
0.50	1.64E-08	3.024E-12
1.0	9.82E-08	1.080E-10
5.0	7.45E-07	5.950E-09
10.0	1.53E-06	2.400E-08
15.0	2.30E-06	5.161E-08
25.0	3.78E-06	1.278E-07
50.0	7.18E-06	3.854E-07
75.0	1.02E-05	6.744E-07
100.0	1.29E-05	9.572E-07
125.0	1.53E-05	1.219E-06
150.0	1.75E-05	1.454E-06
200.0	2.14E-05	1.842E-06
250.0	2.46E-05	2.132E-06
300.0	2.73E-05	2.341E-06
350.0	2.97E-05	2.485E-06
400.0	3.17E-05	2.578E-06
450.0	3.35E-05	2.633E-06
500.0	3.51E-05	2.657E-06
550.0	3.66E-05	2.659E-06
600.0	3.79E-05	2.642E-06
650.0	3.90E-05	2.613E-06
700.0	4.01E-05	2.573E-06
720.0	4.05E-05	2.555E-06
1. Includes radioactive and stable iodine isotopes		

Table 2.9.2-15
LOCA Time Dependent RWT Liquid Temperature

Time (hr)	Temperature (°F)
0.00	105.5
0.40	105.5
0.50	105.5
1.0	105.5
5.0	105.5
10.0	105.5
15.0	105.5
25.0	105.5
50.0	105.5
75.0	105.5
100.0	105.5
125.0	105.5
150.0	105.5
200.0	105.5
250.0	105.5
300.0	105.5
350.0	105.5
400.0	105.5
450.0	105.5
500.0	105.5
550.0	105.5
600.0	105.5
650.0	105.5
700.0	105.5
720.0	105.5

Table 2.9.2-16
LOCA Time Dependent RWT Elemental Iodine Fraction

Time (hr)	Elemental Iodine Fraction
0.00	0
0.40	0.000E+00
0.50	3.691E-04
1.0	2.199E-03
5.0	1.598E-02
10.0	3.129E-02
15.0	4.481E-02
25.0	6.756E-02
50.0	1.073E-01
75.0	1.322E-01
100.0	1.483E-01
125.0	1.589E-01
150.0	1.658E-01
200.0	1.725E-01
250.0	1.735E-01
300.0	1.713E-01
350.0	1.674E-01
400.0	1.625E-01
450.0	1.570E-01
500.0	1.512E-01
550.0	1.454E-01
600.0	1.396E-01
650.0	1.339E-01
700.0	1.284E-01
720.0	1.263E-01

Table 2.9.2-17
LOCA Time Dependent RWT Partition Coefficient

Time (hr)	Elemental Iodine Partition Coefficient
0.00	41.18
0.40	41.18
0.50	41.18
1.0	41.18
5.0	41.18
10.0	41.18
15.0	41.18
25.0	41.18
50.0	41.18
75.0	41.18
100.0	41.18
125.0	41.18
150.0	41.18
200.0	41.18
250.0	41.18
300.0	41.18
350.0	41.18
400.0	41.18
450.0	41.18
500.0	41.18
550.0	41.18
600.0	41.18
650.0	41.18
700.0	41.18
720.0	41.18

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
0.40	7.796E-07
10.0	8.410E-06
25.0	4.771E-05
75.0	1.516E-04
125.0	2.598E-04
200.0	3.859E-04
300.0	4.978E-04
450.0	5.573E-04
600.0	5.717E-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	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	Different based on meteorological data

Table 2.9.2-19 (Continued)
Fuel Handling Accident (FHA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	50 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	500 cfm	Same
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	1.3%	1.8%
% DNB for MSLB Inside of Containment	21%	29%
% Fuel Centerline Melt for MSLB Outside of Containment	0.32%	0.43%
% Fuel Centerline Melt for MSLB Inside of Containment	5.0%	6.1%
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 μCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/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	1.04608	1.03687
Steam Generator Tube Leakage	0.25 gpm per SG (Table 2.9.2-22)	0.25 gpm per SG
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
Steam Release from Intact SGs	Table 2.9.2-21	Different based on different thermodynamic conditions

Table 2.9.2-20 (Continued)
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 Reach 212°F and Terminate Steam Release	12.4 hours	10.32 hours
Containment Volume Containment Leakage Rate 0 to 24 hours after 24 hours	2.506E+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	406,715 lbm Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.	411,500 lbm

Table 2.9.2-20 (Continued)
Main Steam Line Break (MSLB) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
SG Secondary Side Mass	Minimum – 120,724.1 lbm (per SG) Maximum – 226,800 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 – 205,000 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	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	Different based on meteorological data
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	50 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	500 cfm	Same
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 Steam Release Rate

Time (hours)(1)	Intact SG Steam Release Rate (lbm/min)
0	52.23
0.50	26.87
0.75	26.87
1.39	26.87
2.00	27.11
4.00	27.11
6.00	27.11
8.00	27.11
10.50	27.11
12.40	0.00

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	1.552	2.006
0.50	1.680	2.006
0.75	1.768	2.006
1.39	1.783	2.006
2.00	1.828	2.006
4.00	1.878	2.006
6.00	1.923	2.006
8.00	1.973	2.006
10.50	2.006	2.006
12.40	0.000	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 µCi/gm DE I-131 and 518.9 µCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 µCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 µCi/gm DE I-131 (Table 2.9.2-3)	0.1 µCi/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	See Table 2.9.2-24	Different based on different thermodynamic conditions and isolation time
Break Flow Flashing Fraction	Prior to Reactor Trip – 17% (Hot Leg) Following Reactor Trip – 6% (Hot Leg)	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 Reach 212°F and Terminate Steam Release	12.4 hours	10.32 hours

Table 2.9.2-23 (Continued)
Steam Generator Tube Rupture Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
RCS Mass	Pre-accident Iodine Spike: 406,715 lbm Concurrent Iodine Spike: 474,951 lbm	Pre-accident Iodine spike – 423,700 lbm Concurrent Iodine spike – 452,000 lbm
SG Secondary Side Mass	Minimum -120,724 lbm (per SG) Maximum - 226,800 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.	Minimum – 105,000 lbm (per SG) Maximum – 260,000 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.
Atmospheric Dispersion Factors		
Offsite	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	Different based on meteorological data
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	522.7 seconds (Hot Leg Break Rx trip + 50 Sec)	409.2 seconds
Time of Control Room Filtered Makeup Flow	1.5 hours	1.5 hours
Control Room Unfiltered Inleakage	500 cfm	500
Breathing Rates		
Offsite	RG 1.183, Section 4.1.3	Same
Control Room	RG 1.183, Section 4.2.6	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	2544.83	1110.0	1107.3
0.131	Reactor Trip	1724.28	49.2	1.0
0.75	Ruptured SG Isolated	0.00	1.3	37.6
1.00	Unaffected SG tubes Re-covered	26.00	0	37.6
1.50	Manual Realignment of CR Intakes	39.00	0	37.6
2.00	X/Q Change	39.00	0	37.6
8.00	X/Q Change	39.00	0	23.2
12.40	Termination of SG Releases at 212F	0	0	0
1. Flow rates are applied until the next time point.				

Table 2.9.2-25
SGTR 60 μCi/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	474,951 lbm
Total Removal Constants (min^{-1})	
I-131	0.002810
I-132	0.007773
I-133	0.003305
I-134	0.015930
I-135	0.004498

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	170.8	82006
I-132	94.7	45478
I-133	207.8	99767
I-134	88.8	42629
I-135	127.7	61275

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	3.0–4.5 w/o
Maximum Radial Peaking Factor	1.65	1.7
Percent of Fuel Rods in DNB	19%	13.7%
High Burnup Fuel Adjustment Factor	1.04608	1.03687
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Initial RCS Equilibrium Activity	1.0 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 μCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 2.9.2-3)	0.1 μCi/gm DE I-131
Release Fraction from Breached Fuel	RG 1.183, Section 3.2	Same
Steam Generator Tube Leakage	0.5 gpm (Table 2.9.2-31)	0.5 gpm
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
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 Flashing Fraction	 1 hour 5%	 Same Same
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100	Same Same
Time to Reach 212°F and Terminate Steam Release	12.4 hours	10.32 hours

Table 2.9.2-28 (Continued)
Locked Rotor Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
RCS Mass	Minimum - 406,715 lbm (9060 ft^3 at system conditions of 2250 psia and 578.5°F)	Minimum - 411,500 lbm Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.
SG Secondary Side Mass	Minimum – 120,724 lbm (per SG) Maximum – 226,800 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.	Minimum – 105,000 lbm (per SG) Maximum – 205,000 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.
Atmospheric Dispersion Factors		
Offsite	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	Different based on meteorological data
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	50 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	500 cfm	Same

Table 2.9.2-28 (Continued)
Locked Rotor Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Breathing Rates		
Offsite	RG 1.183 Section 4.1.3	Same
Onsite	RG 1.183 Section 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same
Control Room Model	96,228 ft^3 volume 504 cfm Makeup Flow	62,318 ft^3 volume 450 cfm Makeup Flow

Table 2.9.2-29
Locked Rotor Steam Release Rate and Steam Generator Tube Leakage

Time (hr)	Steam Release Rate (lbm/min)	Single SG Tube Leakage (lbm/min)	Total SG Tube Leakage (lbm/min)
0–0.50	5486.15	1.552	3.103
0.50–0.75	2820.86	1.680	3.361
0.75–1.0	2820.86	1.714	3.428
1.0–1.39	2820.86	1.768	3.536
1.39–2.0	2820.86	1.783	3.565
2.0–4.0	2846.36	1.828	3.657
4.0–8.0	2846.36	1.878	3.756
8.0–10.5	2846.36	1.973	3.945
10.5–12.4	2846.36	2.006	4.012
12.4–720	0.00	0.000	0.000

Table 2.9.2-30
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 µCi/gm DE I-131 and 518.9 µCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 µCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 µCi/gm DE I-131 (Table 2.9.2-3)	0.1 µCi/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	1.04608 10 fuel assemblies	1.03687 8 fuel assemblies
Steam Generator Tube Leakage	0.5 gpm (Table 2.9.2-31)	0.5 gpm
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
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	5%	Same

Table 2.9.2-30 (Continued)
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 Reach 212°F and Terminate Steam Release	12.4 hours	10.32 hours
RCS Mass	Minimum -- 406,715 lbm Minimum mass used for fuel failure dose contribution to maximum SG tube leakage activity.	Minimum – 411,500 lbm Minimum mass used for fuel failure dose contribution to maximum SG tube leakage activity.
SG Secondary Side Mass	Minimum – 120,724 lbm (per SG) Maximum – 226,800 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.	Minimum – 105,000 lbm (per SG) Maximum – 205,000 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration. Maximum used for initial secondary inventory release to maximize secondary side dose contribution.
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

Table 2.9.2-30 (Continued)
CEA Ejection Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	50 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	500 cfm	Same
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
Control Room Model	96,228 ft^3 volume 504 cfm Makeup Flow	62,318 ft^3 volume 450 cfm Makeup Flow
Containment Volume	2.506E+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% Elemental iodine – 95% Organic iodine – 95%	Same Same Same
Secondary Containment Drawdown Time	310 seconds	Same
Secondary Containment Bypass Fraction	9.6%	Same
Containment Natural Deposition Coefficients	Aerosols – 0.1 hr^{-1} Elemental Iodine – 2.89 hr^{-1} Organic Iodine – None	Same Same Same

Table 2.9.2-31
CEA Ejection Steam Release Rate and Steam Generator Tube Leakage

Time (hr)	Steam Release Rate (lbm/min)	Single SG Tube Leakage (lbm/min)	Total SG Tube Leakage (lbm/min)
0–0.50	5486.15	1.552	3.103
0.50–0.75	2820.86	1.680	3.361
0.75–1.0	2820.86	1.714	3.428
1.0–1.39	2820.86	1.768	3.536
1.39–2.0	2820.86	1.783	3.565
2.0–4.0	2846.36	1.828	3.657
4.0–8.0	2846.36	1.878	3.756
8.0–10.5	2846.36	1.973	3.945
10.5–12.4	2846.36	2.006	4.012
12.4–720	0.00	0.000	0.000

Table 2.9.2-32
IOMSSV 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 μCi/gm DE I-131 and 518.9 μCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 μCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 μCi/gm DE I-131 (Table 2.9.2-3)	0.1 μCi/gm DE I-131
Steam Generator Tube Leakage	0.5 gpm (Table 2.9.2-33)	0.5 gpm
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
Secondary Side Mass Releases to Environment	Entire inventory in 2 hours	Same
Steam Generator Secondary Side Partition Coefficient	None	Same
SG Secondary Side Mass	Maximum - 226,800 lbm per SG Maximum mass used for initial secondary inventory release to maximize secondary side dose contribution.	Maximum - 205,000 lbm per SG Maximum mass used for initial secondary inventory release to maximize secondary side dose contribution.
Atmospheric Dispersion Factors		
Offsite	Table 2.9.2-9	Different based on meteorological data
Onsite	Table 2.9.2-7	Different based on meteorological data
Control Room Ventilation System		
Time of Control Room Ventilation System Isolation	50 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	500 cfm	Same

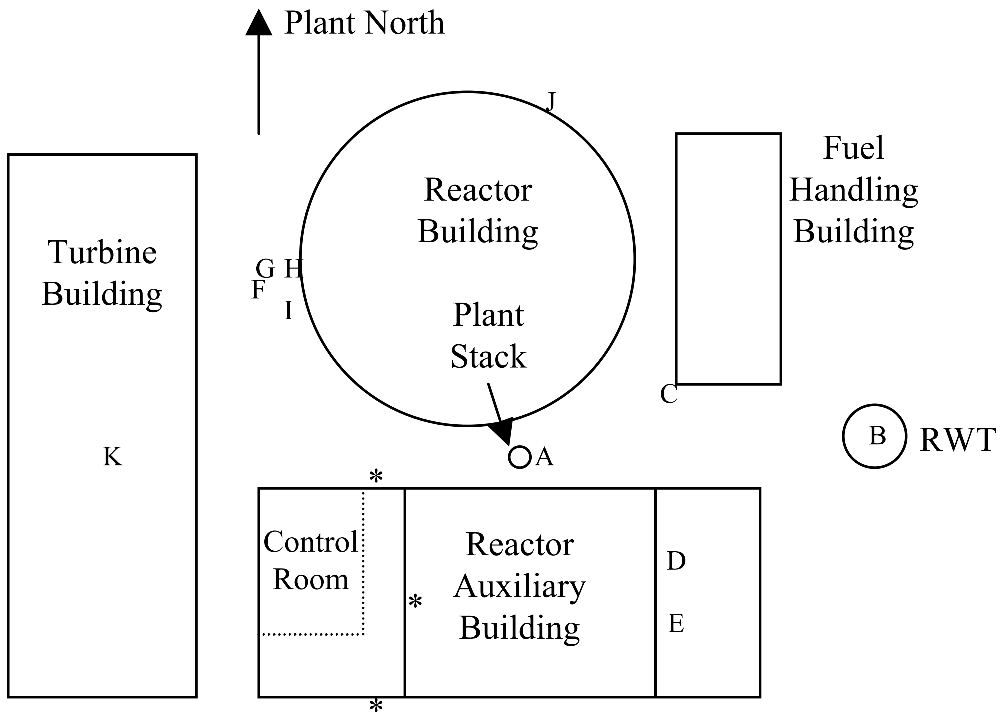
Table 2.9.2-32 (Continued)
IOMSSV Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Breathing Rates:		
Offsite	RG 1.183 Section 4.1.3	Same
Onsite	RG 1.183 Section 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-33
IOMSSV Steam Generator Tube Leakage

Time (hours)	SG Tube Leakage (lbm/min)
0–0.50	3.103
0.50–0.75	3.361
0.75–1.0	3.428
1.0–1.39	3.536
1.39–2.0	3.565
2.0–4.0	3.657
4.0–8.0	3.756
8.0–10.5	3.945
10.5–12.4	4.012
12.4–720	0

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 Closest Point
D – Louver L-7B
E – Louver L-7A
F – Closest ADV
G – Closest MSSV
H – Closest Main Steam Line Point (containment penetration)
I – Closest Feedwater Line Point (containment penetration)
J – Containment Maintenance Hatch
K – Condenser

2.9.3 Radiological Consequences of Gas Decay Tank Ruptures

2.9.3.1 Regulatory Evaluation

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:

- 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 for the duration of the accident;
- 10 CFR 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 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) General Design Criteria (GDCs). In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is discussed in UFSAR Section 3.1.

The current licensing basis with respect to radiological accident consequences 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 total effective dose equivalent for the duration of the accident.

- 10 CFR 100, insofar as it establishes requirements for assuring that offsite radiological doses from postulated accidents will be acceptably low.
- 10 CFR 50.67, insofar as it establishes requirements for Alternative Source Term (AST) licensed plant that offsite and control room operator radiological doses from postulated accidents will be below established guidelines.

On November 26, 2008, the NRC approved Amendment 206 to the St. Lucie Unit 1 operating license, which adopts the 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 1 licensing basis continues to include a WGDT analysis compliant with the 10 CFR 100 acceptance criteria.

In addition to the licensing bases described in the UFSAR, the WGDT was evaluated for St. Lucie Unit 1 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 15.4.2. 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.

2.9.3.2.2 Acceptance Criteria

The offsite dose acceptance criterion for a WGDT rupture accident of 0.1 rem total effective dose equivalent (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 BTP 11-5, 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 WGDT 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) WGDT failure 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 ORIGEN2 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% failed fuel releasing fission product gases into the RCS. The entire RCS noble gas inventory is then assumed to be instantaneously transferred into one WGDT following reactor shutdown. Upon failure, the entire WGDT 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 WGDT is assumed to be insignificant. No credit is taken for isolation of the release path. Table 2.9.3-1 presents the activities of the noble gases in the RCS and the WGDT.

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 inleakage 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 WGDT failure calculation consists of three compartments and four pathways (see Figure 2.9.3-1). Compartment inputs are described in Table 2.9.3-2. Pathway inputs are described in Table 2.9.3-3. RADTRAD-NAI plant and power modeling inputs are described in Table 2.9.3-4.

Breathing rates for offsite locations and the control room, and control room occupancy factors are given in Table 2.9.3-5. Atmospheric dilution factors (X/Q) are given in 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 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 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 1 louver L-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 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 1 CR dose for any WGDT event which may occur at the site. While St. Lucie Unit 2 X/Q candidates may have been considered in this St. Lucie Unit 1 WGDT dose analysis, the selection of the bounding, maximum X/Q’s creates no dependency on the St. Lucie Unit 2 EPU submittal or any planned Technical Specification changes for St. Lucie Unit 2.

The dose conversion factor file used in this analysis reflects dose conversion factors taken from Federal Guidance Reports 11 and 12 (References 7 and 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 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 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 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). 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, Revision 3, Postulated Radioactive Releases Due to a Waste Gas System Leak or Failure, March 2007.

4. USNRC, Regulatory Guide 1.145, Revision 1, Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants.

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 (µCi/gm)	EPA FGR 12, Table III.1 Effective DCF (Sv/(Bq-s-m^{-3})	Tank Activity (Curies)	Activity *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

1. In the DE Xe-133 calculation, the DCF units used are in Sv/Bq-sec-m^3, to be consistent with the given values in EPA FGR 12. By the nature of the arithmetic, the equation:

$$DE = \frac{\text{sum(activity times DCF)}}{\text{DCF}}$$

does not require that the DCFs be converted to Sv/Bq to Rem/Ci (or any other units) to remain correct. Any units 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
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

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	0.0
0.01389	0.0	0.0	0.0	0.0
1.5	0.0	0.0	0.0	0.0
720.0	0.0	0.0	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

2. 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 2.9.3-4
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
Iodine Fraction – organic	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 (m^3/sec)	LPZ Breathing Rate (m^3/sec)	Control Room Breathing Rate (m^3/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/m^3)	Unit 2 X/Q (sec/m^3)	St. Lucie Bounding EAB X/Q (sec/m^3)
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/m^3)	Unit 2 X/Q (sec/m^3)	St. Lucie Bounding LPZ X/Q (sec/m^3)
0.0	7.70E-05	8.24E-05	8.24E-05
2.0	4.38E-05	4.75E-05	4.75E-05
8.0	3.30E-05	3.61E-05	3.61E-05
24.0	1.81E-05	2.00E-05	2.00E-05
96.0	7.97E-06	8.99E-06	8.99E-06
720.0	7.97E-06	8.99E-06	8.99E-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/m^3)	L-7A/ 2L-7A to HVAC X/Q (sec/m^3)	L-7B/ 2L-7B to HVAC X/Q (sec/m^3)	St. Lucie Bounding HVAC X/Q (sec/m^3)
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 /Q via Louver L-11 or 2L-11

Time (hours)	Unit 1 Stack X/Q (Louver L-11) (sec/m^3)	Unit 2 Stack X/Q (Louver 2L-11) (sec/m^3)	Unit 1 L-7A X/Q (Louver L-11) (sec/m^3)	Unit 1 L-7B X/Q (Louver L-11) (sec/m^3)	Unit 2 L-7A X/Q (Louver 2L-11) (sec/m^3)	Unit 2 L-7B X/Q (Louver 2L-11) (sec/m^3)	St. Lucie Bounding Inleakage X/Q (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

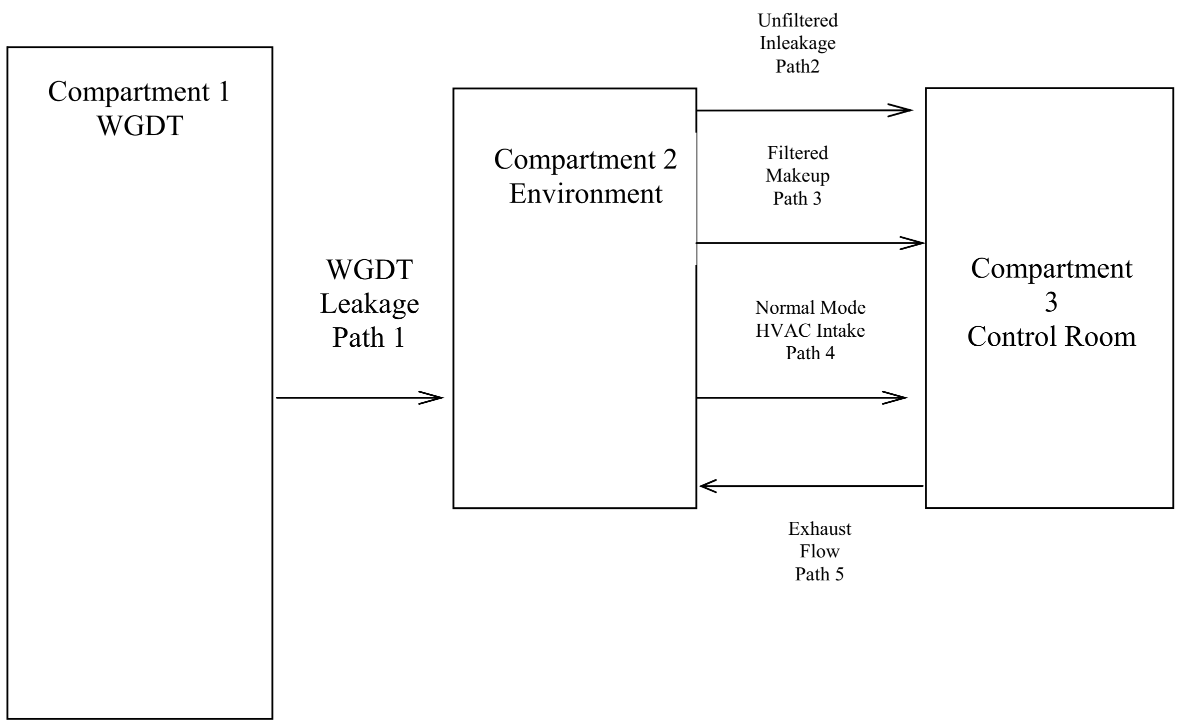
Dose Contribution	TEDE Dose (rem)		
	EAB 30 Days	**LPZ 30 Days**	**CR 30 Days**
WGDT Failure	0.04	0.04	0.19
Acceptance Criteria	0.1[1]	0.1[1]	5[2]
Control Room Unfiltered Inleakage = 500 cfm			

1. The 0.1 REM (TEDE) 30 day dose limit is specified in NUREG-0800 (Reference 3), BTP 11-3 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

FPL conducted its review to ascertain the overall effects the 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 RS-001.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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. 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 St. Lucie Unit 1 current licensing basis 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 MWt with system activity levels stemming from fuel cladding defects in the equivalent of one percent of the fuel rods.

The accessibility of St. Lucie Unit 1 is facilitated by plant shielding and radiation monitoring and is controlled by procedures which 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 11.4, 12.1, and 12.2, 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 Section 12.1.6.1, 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,
- 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 (RGs) 1.4, 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 12.1-10.

A list of vital areas (with accompanying occupancy, dose rate, and dose information) is presented in UFSAR Table 12.1-11. As indicated in UFSAR Table 12.1-11, 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 12.1.6.5 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 Alternative Source Terms (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. As stated in part in the March 18, 2008 letter, “The licensee asserts, and the NRC staff concurs 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 TEDE.” FPL also stated “that since the technical support center (TSC) and the control room (CR) share the same habitability envelope, the shielding study consequences for these areas have been addressed in the current AST LAR (Reference 2).

Regarding post-accident sampling capability, as described in NUREG-0737, Item II.B.3, FPL cited TS Amendments No. 174, (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 12.3.1, the health physics program objectives are:

a. To implement a radiation protection program for protecting the health and safety of plant personnel and the public.

b. To establish and maintain a comprehensive record system which will demonstrate the adequacy of the radiation protection program to ensure that occupational exposures are as low as reasonably achievable and which complies with all applicable Federal and State regulations.

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 12.3.1.

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 bases described in the UFSAR, the radiation protection program (health physics) was evaluated for St. Lucie Unit 1 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
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 Technical Specifications (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 is summarized in UFSAR Section 12.1 which indicates 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 11.1-2, the fuel cycle length was one year. St. Lucie Unit 1 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 CLB 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 cooling system, 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 1 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, results 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 MWt/2700 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 12.1.2.1 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 flux design basis. 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 pre-EPU 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 12.1.2.2 and 12.1.2.3 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 < 0.5 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 mrem/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 12.1.2.4 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 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 12.1.2.5 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 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 EPU reactor coolant versus the pre-uprate 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.
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 12.3, 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 11.4.1, 12.1.4 and 12.2.4.

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, if any, 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 CR and the TSC, are addressed in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST).

The CLB vital area access review is discussed earlier in LR Section 2.10.1.1, item No. 3 and summarized below.

UFSAR Section 12.1.6.1 indicates that a design review of the shielding design was performed in compliance with NUREG 0737, II.B.2. UFSAR Section 12.1.6.5 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 12.1-10. 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 12.1-11. As indicated in UFSAR Table 12.1-11, per the initial review, the areas that needed short term access (i.e., Target Areas 3 through 9), revealed high dose rates and associated accumulated dose at T=1hr which would preclude access at that time. As noted in Table 12.1-11, means for remote operation, additional shielding or plant modifications were provided such that (a) access was no longer required (to Target Areas 3, 4, 5 and 6), or (b) the dose was reduced to a target value below regulatory requirements. As discussed in Section 12.1.6.4 of the UFSAR, the target dose to operating personnel performing necessary functions in vital areas was limited to 3 rem whole body and 18-3/4 rem extremities. FPL's review of the proposed modifications/resolutions listed under the remarks section of UFSAR Table 12.1-11 for Target Areas 7 and 8 has determined that, (a) the modification associated with Target 7 has been completed and thus the estimated dose to the operator is now less than 3 rem, and (b) access to Target 8 should not be listed as a required post-accident action because it addresses a condition that is beyond the licensing basis of the plant. In addition, and as indicated in LR Section 2.10.1.1 and UFSAR Table 12.1-11, the PASS, is no longer used and thus, access to the PASS (Target Area 9), is no longer required.

As noted previously in LR Section 2.10.1.1, and in accordance with the CLB, 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 was performed by FPL of current Emergency Operating Procedures (EOPs), including the potential impact of the EPU on vital access requirements. This review confirmed that except as noted earlier regarding elimination of Target Area 8 as an access requirement, 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 7 (valve station, charging pump cubicles).

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, a containment sump water volume of 1.52E9 cc and a reactor coolant volume of 2.84E8 cc.

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 is 1.87E9 cc and 2.57E8 cc, respectively. The increase in the containment sump water volume is mainly due to an increase in the refueling water tank TS minimum volume, whereas the total RCS volume has been decreased by the pressurizer volume and an assumed allowance for SG tube plugging.

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 limited sub-set of the core inventory 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 1 ft, 2 ft, and 3 ft 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=1 hr 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 area (i.e., Target Area 7), that is deemed to require access following a LOCA.

In summary, a dose scaling factor of 1.46 is utilized to estimate the operator mission dose to the above target area. This value reflects an EPU dose rate scaling factor of 1.32 based on the change in core inventory, and an additional scaling factor of 1.105 due to an estimated reduction in the dilution volume of post-accident fluids.

Based on the target 3 rem whole body dose used to define acceptability of a vital area in the CLB, the estimated EPU operator mission dose at T=1 hr to personnel performing necessary functions in Target Area 7 (Valve Station, Charging Pump cubicles) is 4.4 rem which remains below the regulatory limit of 5 rem whole body.

2.10.1.2.3.3 Results

The limiting calculated dose to an operator performing a vital task is 4.4 rem, thus, demonstrating continued compliance with the regulatory limit of 5 rem whole body listed in NUREG-0737, II.B.2.

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 “As Low As Reasonably Achievable”) is the most limiting. 10 CFR 20 does have a release rate criteria 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 of Appendix I to 10 CFR 50 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 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 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 St. Lucie Unit 1.

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 Unit 1, 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

   For St. Lucie Unit 1, 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 if 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.

   In the long term, the direct shine dose due to radwaste stored onsite could be conservatively estimated to increase by approximately 14.2 percent as: (a) current waste decays and its contribution decreases, (b) the radwaste is routinely moved offsite for disposal, (c) waste generated post-uprate enters into storage and (d) plant capacity factor approaches the target value of 1.0.

   Since the impact on direct shine doses is a result of wastes generated from both units over the plants' lifetime and stored onsite, procedures and controls in the ODCM monitor and control this component of the offsite dose and would limit, through administrative and storage controls, the offsite dose to ensure compliance with the 40 CFR 190 direct shine dose limits.

6. Impact of EPU on Direct Shine

   As noted in the St. Lucie Unit 1 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, however, as discussed above, the direct shine 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 Appendix I to 10 CFR 50 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 skyshine) 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 1 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 criteria 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 12.3.1, the radiation protection 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 Section 12.3.1, 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 12.3.2, 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 12.1.1.1. Design features credited to support FPL's 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 St. Lucie Unit 1 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 on 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), to NRC Document Control Desk, Request for Additional Information Response Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, March 18, 2008.
2. Letter from B. L. Mozafari (NRC), to J. A. Stall (FPL), St. Lucie Plant, Unit 1 – Issuance of Amendment Regarding Alternate Source Term, Amendment No. 206 (TAC No. MD6173), November 26, 2008.
3. Letter from K. N. Jabbour (NRC), to T. F. Plunkett (FPL), 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), 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	St. Lucie ODCM Control[(1)]	-	-
Dose to skin of an individual	30 mrem/yr	St. Lucie 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%

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. FPL's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. 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 Criterion (GDC)-19;
- 10 CFR 50.120;
- 10 CFR 55;
- Generic Letter (GL) 82-33.

Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

St. Lucie Unit 1 Current Licensing Basis

St. Lucie Unit 1 was designed and constructed based on the 1967 draft AEC GDCs. In preparation for issuance of the St. Lucie Unit 1 Final Safety Analysis Report, an effort was made to comply with the newer (1971) final GDCs. See LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report for additional details on the St. Lucie Unit 1 licensing history with respect to GDCs.

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie Unit 1 design relative to the GDC is 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 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.

Following proven power plant design philosophy, 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 abnormal conditions. Shielding is designed to maintain tolerable radiation exposure levels (maximum of 3 rem integrated whole body dose over a 90-day period) following design basis accidents (refer to UFSAR Section 12.1). The control room will be isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system is designed to recirculate control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 12.2. 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.

Consistent with Technical Specification 6.4, Training, the St. Lucie training program is maintained under the direction of the training manager, and each member of the unit staff meets or exceeds the requirements of Regulatory Guide 1.8, Revision 3, Qualification and Training of Personnel for Nuclear Power Plants.

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 response to the requirement of NUREG-0737, Clarification item I.D.1 Control Room Design Review, and Supplement 1 to NUREG-0737 (GL 82-33), FPL established and maintains a human factors engineering program to review the design of the control room and remote shutdown capabilities in order to identify and correct design deficiencies. The design review was performed following the guidelines of NUREG-0700, Guidelines for Control Room Design Review and NUREG-0801, Evaluation Criteria for Detail Control Room Design Review. The continuing human factors engineering program provides for a review of plant changes associated with the control room or the remote shutdown facilities to ensure compliance with the guidance provided in NUREG-0700.

UFSAR Section 13.5 states that written plant procedures are established, implemented and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, those required for implementing the requirements of NUREG-0737 and plant activities including refueling operations, surveillance and test activities of safety-related equipment and the fire protection program implementation, as outlined in Technical Specifications (TS) Section 6.8, Procedures and Programs.

UFSAR Section 7.2 states that the reactor protective system is designed to assure adequate protection of the fuel, fuel cladding and reactor coolant pressure boundary during anticipated operational occurrences. The system is designed to alert the operator when a monitored plant condition is approaching a condition which would initiate protective action (pre-trip alarms). Those nuclear steam supply system (NSSS) conditions which require protective system action are discussed in detail in UFSAR Chapter 15.

In addition to the UFSAR sections detailed above, human performance and human factors related elements are discussed in UFSAR Sections 7.5, Safety Related Display Information; 7.5.2.1, Reactor Protective System Monitoring; 7.7.3.2; Detail Control Room Design Review Implementation; and 7.7.3.3, DCRDR Implementation Evaluation.

UFSAR Section 15.2 includes discussion of credited operator actions as applicable to the various event analyses.

In addition to the licensing bases described in the UFSAR, the human factors were evaluated for St. Lucie Unit 1 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, 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.
- Condensate storage tank (CST) level requirements are changing for cooling down to shutdown cooling (SDC) entry conditions. This effects the EOP figures. Changes are also required in the time until SDC entry conditions are reached. Changes to the time until SDC entry conditions are required. See LR Section 2.5.4.5, Auxiliary Feedwater, for further discussion.
- 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 to low pressure turbines). Due to changes in MWt power level and condenser backpressure values, this setpoint is changing.
- Containment pressure normal operating TS limit will be decreased. Since the EOP setpoint is based on the normal operating containment pressure TS limit, the normal high containment pressure alarm setpoint and normal expected containment pressures may be lowered, see LR Section 2.6.1, Primary Containment Functional Design, for further discussion.

- Procedure changes are required to update reactor coolant system (RCS) subcooling post-accident pressure-temperature (P-T) curves. These curves provide a range of limiting conditions to help verify adequate core cooling, during various plant conditions. These changes are required in support of the low temperature overpressure protection (LTOP) enable temperatures for 54 effective full power years (EFPY).
- 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 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. Since the flow path through the auxiliary spray line can not provide the required flow rate, this flow path is being eliminated as an injection path. Two paths remain available for establishing simultaneous hot leg and cold leg injection.
- The accident analysis assumptions are changing for the minimum high pressure safety injection (HPSI), maximum low pressure safety injection (LPSI), and containment spray (CS) flow rates. 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.
- The safety injection tank (SIT) pressure is increasing to support the small break LOCA (SBLOCA) analysis. Tank pressure will be raised to support injection at an earlier time. Associated setpoints for venting, draining and isolating the SITs will be revised, as required.
- The turbine back pressure alarm setpoint is increasing as a result of higher condenser back pressure at EPU conditions.

Fire protection actions will remain unchanged. For discussion, see LR Section 2.5.1.4, Fire Protection.

Conclusion

The changes to St. Lucie Unit 1 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 station blackout (SBO); a new time limit is required to secure steam generator (SG) blowdown within 30 minutes. In an SBO, the air operated SG blowdown valves will close on the loss of instrument air. The action to ensure SG blowdown has isolated is currently included in the EOPs and will continue to be a verification action for EPU. The new time limit provides inventory conservation with the higher decay heat loads at EPU conditions.
- In the event of a SBO; a revised time limit is required to supply power, ensure there is a continuous source of water, and start one charging pump within 60 minutes. The actions to ensure a source of inventory make up is restored are already included in the EOPs. The new time limit is bounded by the current time frame in which this activity would occur following the steps of the existing EOPs.
- 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 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.
- 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. Since the flow path through the auxiliary spray line can not provide the required flow rate, this flow path is being eliminated as an injection path.

- In the event of a safety injection actuation signal/containment isolation actuation signal (SIAS/CIAS); a new action is required to restore instrument air to containment. For EPU, on a SIAS/CIAS, the containment instrument air compressors will be de-energized and the instrument air to containment will be isolated. This new action is required to support existing steps for controlled bleedoff restoration for the RCPs.
- The containment hydrogen purge system will be upgraded to provide capability for online venting. This includes upgrading the manual containment isolation valves to provide remote-manual control capability. Additionally, the valves will automatically close on a CIAS. Valve position indication (open/close) will be provided in the control room. In the event of a CIAS; a new action is required to verify the containment hydrogen purge valves closed.
- In the event of a 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 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 first stage pressure –turbine first stage pressure is changing. 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 for the following parameters:

   - 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 Cv 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 input 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.
   - Containment Venting
     - The containment hydrogen purge system will be upgraded to provide capability for online venting, which will support a decreased TS Limiting Condition for Operation for allowable containment pressure. The existing containment hydrogen purge system manual containment isolation valves will be upgraded to provide remote-manual control capability, and they will automatically close on a CIAS. Open/close valve position indication will be provided in the control room.
   - 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 control are being replaced with electronic instruments. The existing backup level switch control functions will not be changing.

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 Test Plan.

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 Section 7.5.4.1. 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 Sections 7.5.4.1 and 7.5.4.2 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:

- CST inventory level
- Containment pressure
- Normal core full power ΔT

- Safety injection flow rate (combined hot and cold leg injection)
- 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 (JITT) startup training 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, some 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 1 will continue to meet its current licensing basis with respect to the requirements of GDC-19, 10 CFR 50.120, and 10 CFR 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 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 (Reference 1).

St. Lucie Unit 1 Current Licensing Basis

The St. Lucie Unit 1 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 14.0 of the St. Lucie Unit 1 Safety Evaluation Report (SER) (Reference 2), Section 14.0 of SER Supplement 2 (Reference 3), NRC to FPL letter dated March 1976 (Reference 14), and NRC to FPL letter dated April 30, 1976 (Reference 4).

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% reactor thermal power. Succeeding levels were at approximately 50%, 80%, and 100% reactor thermal power.

The results of the startup and power ascension testing program were reported to the NRC in the St. Lucie Unit 1 Startup Report with the letter dated January 21, 1977 (Reference 5), a request for a supplement due date extension dated April 5, 1977 (Reference 6), and the Startup Report Supplement dated May 27, 1977 (Reference 7).

Amendment 48 to the operating license (Reference 8) was issued on November 23, 1981, which authorized an increase in the plant output from 2560 to 2700 MWt.

In addition to the licensing bases described in the UFSAR, the power ascension testing was evaluated for St. Lucie Unit 1 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 1 has significant operating experience at its current operating conditions. St. Lucie Unit 1 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 affects. 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 affects. For both St. Lucie Unit 1 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%. 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 594°F to 601.8°F, respectively. SG outlet nozzle best-estimate pressure will be very close to current operation and will decrease from 858 psia to 856 psia.

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 1 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% uprate to 3026 MWt) that is nearly identical to the St. Lucie Unit 1 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 (a 8.0% uprate to 3716 MWt) that is higher than the St. Lucie Unit 1 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 Section 14.1.4, of the original FSAR,
- St. Lucie Unit 1 Startup Report and Startup Report Supplement (References 5 and 7),
- 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 proposed 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 all 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% 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% 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% of EPU power (2700 MWt), power will be slowly and deliberately increased through four additional test plateaus, each differing by approximately 3% 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, has been 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. A description of the piping vibration monitoring program is provided in LR Section 2.2.2.2.

Observed piping vibrations will be evaluated to ensure that damage will not result. 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 9).

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 piping and equipment vibration monitoring 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 includes 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. 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 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% to 15% 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 valves. Main FW system response will be monitored during power ascension. This includes the transition from the 15% 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.

Moderator Temperature Coefficient (MTC) Testing at Power

Following every refueling, an MTC measurement is performed within several days of achieving 100% power and equilibrium Xenon conditions. The primary purpose of the test is to measure MTC to satisfy TS Surveillance Requirements. However, the test method includes small load

(20-50 megawatts electric (MWe)) changes and RCS temperature changes, and the transient response will be monitored and evaluated.

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 all tests performed during original power ascension, regardless of the power level at which they were performed. The table contains all items from FSAR Chapter 14 Table 14.1-2, Post Loading Testing Summary, as well as additional at-power tests documented in the St. Lucie Unit 1 Startup Report and Startup Report Supplement.

The first column of LR Table 2.12-2 lists the UFSAR table item number or reference to the Startup Report. The second column of LR Table 2.12-2 lists the test and conditions based on UFSAR Table 14.1-2. Clarification for the test conditions is provided where necessary. For tests not included in the UFSAR, this column lists the test description, conditions, and section from the Startup Report or Startup Report Supplement.

The third column of Table 2.12-2 specifies whether the testing activity will be replicated as part of the proposed 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 UFSAR Table 14.1-2. For tests not included in the UFSAR, this column lists the objective based on the test purpose from the Startup Report or Startup Report Supplement.

The fifth column of 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 10). 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 outage SL1-24 consistent with ANS-19.6.1 and normal FPL practices. This activity will be completed prior to exceeding 5% reactor power. No additional low power physics testing is required specifically for EPU. For those reasons, all 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,
- Critical boron check, and
- Moderator temperature coefficient determination.

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:

- Power coefficient measurement,
- Simulated control element assembly (CEA) ejection test,
- Static CEA drop test,
- CEA drop,
- Load cycle test (also see LR Section 2.12.1.2.7), and
- Power defect and Xenon worth after shutdown.

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 will take place during refueling outage SL 1-23 (Spring 2010) and refueling outage SL 1-24 (Fall 2011). Power ascension to the EPU operating condition of 3020 MWt reactor power will follow refueling outage SL 1-24. Post-modification testing will take place during the outage or during post-outage power ascension in which the modification is implemented. Significant modifications are listed in LR Table 2.12-3 and are planned for implementation in outage SL 1-24.

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 12).

CENTS has been used on other CE designs. Waterford 3, a CE design similar to St. Lucie Unit 1, 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 13), 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 1 100% power automatic reactor trip from RCP 1A2 trip on June 5, 2001;
- Unit 1 100% to 68% power ramp on August 20, 2008;
- Unit 1 42% to 83% power ramp on March 14, 2008;
- Unit 2 manual reactor trip from 100% power on June 4, 2008 following a loss of a main FW pump; and
- Unit 2 manual reactor trip from 100% power on June 7, 2008 following a condensate pump trip.

The Unit 2 events were chosen to supplement the Unit 1 events based on their recent history, high power level, available plant data, and the fact that Unit 2 is sufficiently close to Unit 1 to support validation of the 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. A summary of the transient analyses results is presented in LR Table 2.8.5.0-5, Core Power Distribution Parameters. For each transient, the results were acceptable. 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 1976 and 1977. 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 1976 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.
- 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. Additional drawbacks from inducing a large transient include the potential impact on St. Lucie Unit 2 and the potential to challenge the stability of the electric power grid 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,
- Load cycle test,
- Turbine trip,
- Generator trip,
- Partial loss of flow 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, testing was performed at approximately 30%, 50%, and 90% power. At each plateau, four transients were performed: a 2% load reduction at 0.5%/min, a 10% load reduction at 1%/min, 10% load reduction at 5%/min, and finally a 5% very rapid load reduction, stabilization, then another 5% very rapid load reduction. The turbine runback feature, involving a rapid 10% load reduction, was also verified. 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 28–31, 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% 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% step load change from EPU operating conditions verses a 10% step load change from (approximately) current full power conditions. These two cases are discussed in more detail below.

Case 8 models a 10% step load change from full EPU power. No operator actions were assumed and CEA control was in manual. The reactor power decreased to about 93%. SBCS valves opened and limited the increase in steam pressure. The maximum pressurizer pressure was 2349 psia. The maximum pressurizer level was 73%. The pressurizer level was nearly back to the program level within 15 minutes. The maximum steam generator pressure was 935 psia.

Case 9 models a 10% step load change from 90% 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 85%. SBCS valves opened and limited the increase in steam pressure. The maximum pressurizer pressure was 2344 psia. The maximum pressurizer level was 72%. The pressurizer level was back to the program level within 15 minutes. The maximum steam generator pressure was 933 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% step load change.

Recent operational data demonstrates load reduction capability. On August 20, 2008, St. Lucie Unit 1 reduced power from 100% to 68% at a ramp rate of approximately 0.25%/min. Control systems performed adequately to allow a smooth transient. Although not matching the load change and ramp rate of initial power ascension testing, this transient does demonstrate the ability to sustain an extended load reduction that is not typical of daily operation.

Waterford 3 provides related operating experience (Reference 15). 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% power in anticipation of Hurricane Katrina. Load was reduced at a rate of approximately 0.8%/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%/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 1. 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.

Load Cycle Test

The load cycle test was conducted to evaluate plant and nuclear parameters in a typical load cycle operation. During the original startup test program, load was dropped from approximately 85% steady-state reactor power to approximately 40% power at a rate of approximately 30%/hr. Power was maintained at 40% for approximately one hour and then load was raised at 30%/hr for the return to 85% power. Power distribution measurements were performed after the load drop and after the load rise. Plant parameters (e.g., SG levels, pressurizer pressure) were monitored during the load changes. Nuclear and plant parameters were within acceptable limits.

This test was envisioned as a typical load cycle operation at the time of the original startup. However, load maneuvering is not part of present day practice. Base load operation has been used and is intended to be used in the future, so the objective of this test serves no present day purpose.

Analyses were performed using the CENTS code for numerous load transients as shown on LR Table 2.12-4. Cases 30 and 31 modeled the load changes performed in the load cycle test. The CENTS results for these two cases showed that plant parameters were all steady with no major perturbations, the NSSS functional requirements applicable to these transients 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.

To summarize, St. Lucie Unit 1 is not a load follow plant and, even if it was a load follow plant, the analyzed load cycle transient shows acceptable response and stability. When adding the avoided risk of an unnecessary plant transient, a load cycle test is not required in the EPU power ascension test plan.

Turbine Trip

The purpose of the turbine trip test was to verify control systems perform as designed to bring the unit to hot standby conditions following a trip from 100% power. During the original startup test program, the turbine trip test was performed from approximately 100% power. A manual turbine trip was initiated, and then the reactor and generator 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.

Analyses were performed using the CENTS code for numerous transients as shown on Table 2.12-4. Cases 1 and 33 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 973 psia. Following the SBCS quick open, the SBCS provides modulation control near the SBCS pressure setpoint. The minimum SG level was at 29% which is above the auxiliary feedwater actuation system (AFAS) low level setpoint. The minimum pressurizer pressure was 1811 psia. The pressurizer level dropped below the heater cutoff setpoint and the pressurizer heaters were de-energized. The minimum pressurizer level was about 20%.

Case 2 models a turbine trip from 90% 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. A SBCS quick open signal occurs on reactor trip. The maximum SG pressure was 953 psia. Following the SBCS quick open, the SBCS provides modulation control near the SBCS pressure setpoint. The minimum SG level was at 23% which is above the AFAS low level setpoint. The minimum pressurizer pressure was 1859 psia. The pressurizer level dropped below the heater cutoff setpoint and the pressurizer heaters were de-energized. The minimum pressurizer level was about 26%.

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 1 operational data includes only one trip from full power in the past decade. On June 5, 2001, a RCP 1A2 trip caused an automatic reactor trip from 100% power. All safety equipment operated per design and the unit was safely brought to Mode 3. This event demonstrates 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 15). On November 11, 2005, a manual reactor trip from 100% 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 1.

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 1.

The CENTS cases demonstrate that a turbine 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 turbine trip test from a high power level is unnecessary. Therefore, an at-power turbine trip test from a high power level is not required in the EPU power ascension test plan.

Generator Trip

The purpose of the generator trip test was to verify the unit can accept a design load rejection (i.e., a loss of generator load from 100% power). During the original startup test program, the Generator Trip Test was performed from approximately 100% 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 above, the CENTS code was used to analyze a turbine trip from full power, the NSSS functional requirements applicable to the transient were met, and all of the NSSS control systems performed adequately with the EPU setpoints. This analysis demonstrates that a generator trip from full power EPU conditions results in acceptable plant response. 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.

Based on this discussion and the turbine trip analysis from above, an at-power generator trip test is not required in the EPU Power Ascension Test Plan.

Partial Loss of Flow Test

The purpose of the partial loss of flow test was to observe plant response to a partial loss of reactor coolant flow while at power and to verify that the reactor protection system (RPS) low flow trip units initiate a reactor trip. During the original startup test program, the partial loss of flow test was performed from approximately 80% power. One RCP was turned off, and then the reactor tripped on low flow. All four of the low flow trip units responded and overall plant response was as expected.

Analyses were performed using the CENTS code for numerous transients as shown on LR Table 2.12-4. Case 34 modeled a trip from the loss of one RCP from 80% EPU power. The NSSS functional requirements applicable to the transient were met and all of the NSSS control systems performed adequately with the EPU setpoints. This analysis demonstrates that a loss of one RCP from 80% power results in acceptable plant response.

Similar events have occurred within the past 12 years of St. Lucie Unit 1 operation. On December 31, 1997 with the plant operating at 100% power, one RCP tripped, resulting in an automatic reactor trip from RPS low flow trip channels. On June 5, 2001 with the plant operating at 100% power, one RCP tripped, resulting in an automatic reactor trip from RPS low flow trip channels. In both cases, the reactor tripped on low reactor coolant flow and the unit was safely shut down. These events demonstrate the ability to sustain an automatic reactor trip from the loss of one RCP. In addition, these events occurred from the current full power level of 2700 MWt, or 89% of the EPU full power of 3020 MWt. In comparison, the original startup partial loss of flow test was performed from 80% of the original full power level of 2560 MWt.

In summary, the analyzed partial loss of flow from 80% EPU power transient shows acceptable stability and response, and system response has been adequate for similar, but unplanned, St. Lucie Unit 1 events. Based on this analysis and the avoided risk of an unnecessary plant transient, an at-power partial loss of flow test is not required in the EPU power ascension test plan.

Natural Circulation Test

The purpose of natural circulation testing was to demonstrate the capability of natural circulation to remove core decay heat while maintaining NSSS parameters within design limits. During the original startup test program, the total loss of flow/natural circulation test was performed from 40% power. All four RCPs were turned off simultaneously, the reactor tripped on low flow, and the pumps were not restarted until natural circulation flow had been verified. The test demonstrated that natural circulation flows were adequate to remove heat and maintain NSSS parameters in an acceptable range.

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 1 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. NUREG-0800, Standard Review Plan, Section 14.2.1, Generic Guidelines for Extended Power Uprate Testing Programs, August 2006.
2. Safety Evaluation of the St. Lucie Plant Unit No. 1, November 8, 1974.
3. Supplement 2 to the Safety Evaluation of the St. Lucie Plant Unit No. 1, March 1, 1976.
4. NRC Letter to FPL, April 30, 1976.
5. FPL Letter to NRC, L-77-28, St. Lucie Unit 1 Startup Report, January 21, 1977.
6. FPL Letter to NRC, L-77-109, April 5, 1977.
7. FPL Letter to NRC, L-77-164, St. Lucie Startup Report Supplement, May 27, 1977.
8. Amendment No. 48 to Facility Operating License No. DPR-67 for St. Lucie Unit No. 1, November 23, 1981.
9. 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.
10. ANS-19.6.1, Reload Startup Physics Tests for Pressurized Water Reactors.
11. NRC Regulatory Guide 1.70, Revision 2, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, September 1975
12. Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, Technical Description Manual for the CENTS Code, March 2005.
13. Letter from Entergy to the NRC, W3F1-2004-0004, January 29, 2004.
14. NRC Letter to FPL, March 1976.

15. Letter from Entergy to the NRC, W3F1-2005-0083, 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
MTC Test at HFP	Determine MTC											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 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								

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 System Mods	Monitor and tune, as necessary, new HD valves.			x	x	x	x	x	x	x	x	x
HD Pump Mods	Monitor and tune, as necessary, new 1B HD Pump discharge valve. 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 EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
1	<u>CEA Drop Tests</u> RCS Temperature of 515°F (also performed at cold conditions)	No	To measure the drop time of CEA assemblies under full flow and no flow conditions, plus three additional measurements on the two fastest and two slowest CEAs under both flow conditions.	Rod drop testing is performed as a normal post refueling TS surveillance. There are no EPU modifications that will affect rod drop time; therefore this test is not required to be re-performed at the EPU condition.
2	<u>RTD Verification</u> Various temperatures during system heatup at zero power.	No	To verify operability of resistance temperature detectors (RTDs).	Proper operation of the RTDs is verified by channel calibrations and channel checks. The EPU will marginally raise the reactor coolant temperature, but well within the range of the RTDs.
3	<u>Nuclear Design Check Tests</u> Various CEA group configurations at hot, zero power	No	To verify nuclear design predictions for endpoint boron concentrations and isothermal temperature coefficients.	This particular test, in part, is within the scope of the current low power physics test program. Low power physics testing will be performed during refueling outage SL1-24, but no low power physics testing is required specifically for EPU. See LR Section 2.12.1.2.4 for further discussion.
4	<u>CEA Group Calibration</u> All CEA groups at hot, zero power	No	To verify nuclear design predictions for CEA groups.	This particular test is not part of the current low power physics test program. See LR Section 2.12.1.2.4 for further discussion.
5	<u>Power Coefficient Measurement</u> 50% and 100% power (performed at 50%, 80%, and 100% power)	No	To verify that nuclear design predictions for differential power coefficients are valid.	This at-power physics test is not necessary for inclusion with the EPU power ascension test plan. See LR Section 2.12.1.2.4 for further discussion.
6	<u>Automatic Control System Checkout</u> Approximately 20% power (performed from 30%, 50%, and 90% power)	Yes (in part)	To verify the control system response characteristics for the SG level control system, and turbine control system.	System parameters will be monitored per NSSS and BOP data collection activities as shown in LR 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.

Table 2.12-2 (Continued)
Comparison of EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
7	Power Range Instrumentation Calibration During static and/or transient conditions at: 20%, 50%, 80%, 100% power	Yes	To calibrate the flux and temperature power range instrumentation required for protection and control.	Power indication monitoring and calibration are included with the EPU power ascension test plan, as shown on LR Table 2.12-1.
8	Chemical and Radiochemical Analysis During static and/or transient conditions at: 20%, 50%, 80%, 100% power	No	To verify integrity of fuel and corrosion inhibiting effects of reactor coolant chemistry.	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.
9	Radiation Survey and Shielding Effectiveness 20%, 50%, 100% power	Yes	To determine adequacy of radiation shielding and measure activity for short term access inside containment and in parts of plant accessible to personnel.	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 LR Table 2.12-1, and survey results updated as necessary.
10	Pressurizer Effectiveness Test hot, shutdown	No	To verify that pressurizer pressure can be reduced at the required rate by pressurizer spray actuation.	EPU will have no affect on the operation of the pressurizer spray valves and does not invalidate the test as originally performed.
11	Minimum Shutdown Verification hot, zero power	No	To measure net shutdown margin with one “stuck” CEA.	This particular test is not part of the current low power physics test program. See LR Section 2.12.1.2.4 for further discussion.
12	Simulated CEA Ejection Test hot, zero power	No	To measure reactivity of ejected CEA from zero power CEA insertion limit.	This particular test is not part of the current low power physics test program. See LR Section 2.12.1.2.4 for further discussion.
13	Simulated CEA Ejection Test 50% power	No	To measure peaking factors with one CEA ejected from typical operation configuration.	This at-power physics test is not necessary for inclusion with the EPU power ascension test plan. See LR Section 2.12.1.2.4 for further discussion.

Table 2.12-2 (Continued)
Comparison of EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
14	Ex-Core Detector Calibration ~50% of rated power	Yes	To calibrate the ex-core detectors to in-core power distribution measurements.	Linear power range channel and Shape Annealing Factor monitoring and adjustment are included with the EPU power ascension test plan, as shown on LR Table 2.12-1.
15	Static CEA Drop Test ~50% of rated power	No	To measure the power distribution with a partially and fully inserted rod from a typical operating configuration.	This at-power physics test is not necessary for inclusion with the EPU power ascension test plan. See LR Section 2.12.1.2.4 for further discussion.
16	Effluent Monitors ~100% of rated power	No	To compare calibration of installed units with waste handling system test samples.	EPU will have no affect on the operation of the installed effluent monitors and does not invalidate the test as originally performed. Current plant controls are adequate and will remain in place to maintain the monitors and settings at the uprated conditions. (Ref: LR Sections 2.5.6.1 and 2.5.6.2)
17	Dynamic CEA Drop ~50% of rated power	No	To determine effectiveness of instrumentation to detect a dropped rod and to verify associated automatic response.	The ability of plant instrumentation to detect and respond to a dropped control rod has not changed with EPU. In addition, dropped rod events since initial startup have demonstrated the ability of plant instrumentation to detect and respond. Similar testing for EPU is not necessary. See LR Section 2.12.1.2.4 for further discussion, as this activity can also be considered an at-power physics test.
18	Load Reduction Test ~10% step reduction from ~75% of rated power	No	To verify settings for turbine runback.	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.
19	Load Cycle Test ~40% to ~85% of rated power	No	To verify that all systems are capable of sustaining load follow operations without encountering unacceptable operational limits through a typical weekly cycle.	This transient test is not necessary for EPU. See discussion of Load Cycle Test in LR Section 2.12.1.2.7 for further discussion related to plant transients and LR Section 2.12.1.2.4 for further discussion related to reactor physics testing.

Table 2.12-2 (Continued)
Comparison of EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
20	<u>Turbine-Generator Startup Tests</u> Pre- and Post- Synchronization	No	To verify that the turbine-generator unit and associated controls and trips are in working order and ready for service.	Normal Operations procedures verify the turbine-generator unit and associated controls and trips are in working order and ready for service prior to and during startup. Any modifications to turbine controls will be tested under the modification process.
21	<u>Turbine-Generator Acceptance Run</u> ~25% to ~100% of rated power (performed at 100% power as part of the NSSS Acceptance Run)	Yes	To verify manufacturers performance warranties.	An electrical output test at the final test plateau is included with the EPU power ascension test plan, as shown on LR Table 2.12-1.
22	<u>Turbine Control Valve Tests</u> ~75% of rated power	Yes (in part)	To verify capability of exercising control valves at significant load and evaluate function of valves and controls.	The main purpose of this test is to verify closure ability for the turbine reheat stop, interceptor, throttle, and governor valves. This will be done prior to turbine startup and is included with the EPU power ascension test plan, as shown on LR Table 2.12-1. In addition, the valves will close against steam during the turbine overspeed trip test. The capability to perform turbine valve testing at significant power is not impacted by EPU. Finally, this capability is demonstrated on a regular basis by plant procedures when turbine valve surveillance testing is performed at power.
23	<u>NSSS Acceptance Run</u> 100 hours of rated full power	No	To verify reliable steady-state full power capability.	During the initial power ascension, this test was an NSSS reliability demonstration of steady-state operation and a utility/NSSS vendor warranty issue for initial operation. Therefore, this test is not considered to be necessary for the EPU power ascension test plan.

Table 2.12-2 (Continued)
Comparison of EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
24	Loss of Reactor Coolant Flow/Steady-State Flow Test Post core Hot Functional (RCS flow measurement also performed at 80% power)	Yes (in part)	To measure dynamic response characteristics of the RCS as pumps coast down and obtain post core load flow data.	EPU has no adverse affect on the RCS 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 EPU power ascension test plan, as shown on LR Table 2.12-1, as a verification of adequate flow at the uprated conditions.
25	Generator Trip 100% power (performed from 100% power)	No	To verify unit can accept design load rejection.	This transient test is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion.
26	Turbine Trip ~100% of rated power (performed from 100% power)	No	To verify control systems perform as designed to bring unit to hot standby condition.	This transient test is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion.
27	Control Room Inaccessibility 10% of rated power (performed from 50% power)	No	To verify unit can be safely shutdown from outside control room and be maintained at hot shutdown.	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.
28	Loss-of-Offsite Power 10% of rated power (performed from 20% power)	No	To test all systems required to operate during the loss-of-offsite power.	The original test demonstrated that the plant could lose offsite 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 offsite 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.

Table 2.12-2 (Continued)
Comparison of EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
N/A (from S/U Report)	<u>Core Power Distribution Monitoring</u> Major testing power plateaus [Startup Report - 6.13] [Startup Report Supplement - 6.1]	Yes	Detailed core power distribution measurements performed under steady-state conditions during power ascension testing to verify that fuel assembly power fractions, axial power distributions and peak linear heat rates were within acceptable limits.	Core power distribution measurements are included with the EPU power ascension test plan, as shown on LR Table 2.12-1. Also see LR Section 2.12.1.2.4 for further discussion.
N/A (from S/U Report)	<u>Total Radial Peaking Factor</u> Major testing power plateaus [Startup Report - 6.10] [Startup Report Supplement - 6.21]	Yes	To measure the total radial peaking factor F_r^T	Core power distribution measurements are included with the EPU power ascension test plan, as shown on LR Table 2.12-1. Also see LR Section 2.12.1.2.4 for further discussion.
N/A (from S/U Report)	<u>Power Defect and Xenon Worth after Shutdown</u> from 80% power [Startup Report Supplement - 6.7]	No	To measure power defect and to measure the xenon worth after shutdown as a function of time.	This at-power physics test is not necessary for inclusion with the EPU power ascension test plan. See LR Section 2.12.1.2.4 for further discussion.
N/A (from S/U Report)	<u>Steam Generator Feedwater Hammer Test</u> From 33% power and 40% power [Startup Report - 6.15] [Startup Report Supplement - 6.9]	No	To verify the absence of any water hammer in the SG FW piping when the SG was drained below the feed ring and then refilled.	The original CE 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.
N/A (from S/U Report)	<u>Partial Loss of Flow Test</u> From 80% power [Startup Report Supplement - 6.6]	No	To observe plant response to a partial loss of reactor coolant flow while at power and verify that the RPS low flow trip units initiate a reactor trip.	This transient test is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion.
N/A (from S/U Report)	<u>Total Loss of Flow/Natural Circulation Test</u> from 40% power [Startup Report Supplement - 6.8]	No	To verify that the RPS would initiate a reactor trip on low flow after a total loss of RCS flow and to verify that natural circulation occurs.	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 EPU Tests to Original Startup Tests

FSAR Table 14.1-2 Item No.	Test Description and Conditions FSAR Table 14.1-2 [or Startup Report]	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Explanation/Justification
N/A (from S/U Report)	<u>20% Power Trip Test and Auxiliary to Startup Transformer Auto transfer Test</u> from 20% power [Startup Report - 6.3]	No	To measure plant response to a reactor trip from 20% power and to verify proper transfer of the 4160 and 6900 volt A.C. buses from the auxiliary (in plant) to the startup (offsite) transformer.	The original test served as a predecessor check to the trips from 100% power. These trips from 100% power are listed in this table for FSAR Table 14.1-2 Item No. 25 and 26 and further discussed in LR Section 2.12.1.2.7. No changes with EPU impact the capability to transfer from the auxiliary (in plant) to the startup (offsite) transformer, which is verified each refueling outage. This transient test is not necessary for EPU.
N/A (from S/U Report)	<u>Turbine Overspeed Test</u> from ~14% power [Startup Report Supplement - 6.22]	Yes	To demonstrate that the turbine overspeed trip mechanism would trip the turbine at a speed of 1998 +0/-10 rpm and to verify that overspeed trip weight will operate when the trip weight body is subjected to oil pressure.	A turbine overspeed trip test is included with the EPU power ascension test plan, as shown on LR Table 2.12-1.
N/A (from S/U Report)	<u>DDPS Calorimetric and DDPS Snapshot</u> Major testing power plateaus [Startup Report Supplement - 6.25]	Yes	Digital Data Processor System (DDPS) calorimetric and snapshot performed for power level and power distribution monitoring.	Thermal power and core power distribution monitoring are included with the EPU power ascension test plan, as shown on LR Table 2.12-1.

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 (during outage 1-24)
Main Feedwater Pump Replacement	Replace main FW Pumps (no motor replacement required) to support full load FW flow at EPU conditions.	SL 1-24	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.	SL 1-24	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.	SL 1-24	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.	SL 1-24	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 (during outage 1-24)
LEFM - Measurement Uncertainty Recapture	Install LEFM for improved FW flow measurement accuracy. Note: The LEFM Modification is discussed in LR Section 2.4.4, Measurement Uncertainty Recapture Power Uprate.	SL 1-24	No	No	Factory Acceptance Test (FAT) of electronics unit. Transducer cable testing. Hydrostatic testing of spool piece. Flow Test of spool piece by third party. Transducer testing. Software testing of plant computer and electronics unit. Vendor commissioning procedure. Functional checkout (performed during EPU startup testing).	Functional checkout at ~ 95% power, then monitoring up to 100% power.
Heater Drain Pump Replacement	Replace the 1A and 1B HD pumps rotating elements (no motor replacement required).	SL 1-24	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.	SL 1-24	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.
1B Heater Drain Pump Discharge Valve Replacement	Replace the 1B HD pump discharge valve to accommodate the increased flow demand for EPU conditions.	SL 1-24	Yes	Yes	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.

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 (during outage 1-24)
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.	SL 1-24	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.
MSR Replacement	Replace the MSRs due to the increased flow rates at the EPU conditions.	SL 1-24	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.	SL 1-24	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.	SL 1-24	No	No	Standard post-maintenance testing.	Parameters monitored during power ascension.
Main Steam Isolation Valve (MSIV) Upgrade	Upgrade the MSIV for increased steam flow at EPU conditions.	SL 1-24	No	No	Full closure stroke time test.	Not required.
SBCS Capacity Increase	Increase SBCS flow capacity to provide added relief capacity for higher EPU steam flow.	SL 1-24	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.

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 (during outage 1-24)
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.	SL 1-24	No	No	Functional/performance verification.	Parameters monitored during power ascension.
Iso Phase Bus Duct Cooling Upgrade	Upgrade the capacity of the Iso Phase Bus Duct Cooling System to meet higher heat load requirements.	SL 1-24	No	No	Air flow performance test.	Iso phase bus duct temperatures monitored during power ascension.
Main Transformer Cooler Upgrade (1A & 1B)	Provide additional heat removal capacity by upgrading the main transformers with new cooler packages (i.e., pumps and coolers).	SL 1-24	No	No	Functional/performance test of cooling system (performed during EPU startup testing).	Monitor temperatures during power ascension. Functional/performance test of cooling system.
HP Turbine Steam Path Upgrade	Replace the HP turbine steam path to accommodate increased steam flow at EPU conditions.	SL 1-24	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.	SL 1-24	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.

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 (during outage 1-24)
DEH Computer Replacement	Replace the Turbine DEH computer.	SL 1-24	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.	SL 1-24	No	No	Pre-operation vendor electrical tests.	Parameters monitored during power ascension.
Generator Current Transformers (CTs), Bushings and Power System Stabilizer (PSS)	Replace the generator bushings, CTs, and PSS to increase generator electrical capability.	SL 1-24	No	No	For CTs and bushings, vendor mechanical and electrical tests. For PSS, vendor commissioning testing.	Parameters monitored during power ascension. For PSS, vendor at-power commissioning testing.
Generator Hydrogen Seal Oil Pressure Increase	Increase generator Hydrogen pressure to 75 psig and Hydrogen seal oil pressure to 87 psig.	SL 1-24	No	No	Standard post-maintenance testing.	Not required.
Main Generator Hydrogen Cooler Replacement	Replace Hydrogen coolers to meet the increased generator electrical capability.	SL 1-24	No	No	Functional/performance testing.	Parameters, such as temperatures, 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 (during outage 1-24)
Exciter Cooler Replacement	Replace exciter cooler to meet the increased generator electrical capability.	SL 1-24	No	No	Functional/performance testing.	Parameters, such as temperatures, monitored during power ascension.
Hot Leg Injection Flow Increase	Increase Hot Leg injection flow by resizing a flow path to preclude boron precipitation.	SL 1-24	No	No	Standard post-maintenance testing.	Not required.
Containment Purge Modification	Addition of remotely operated containment isolation valves to allow online containment purge.	SL 1-24	No	No	Inservice Testing Program testing. Integrated safeguards testing.	Not required.
Increase Safety Injection Tank (SIT) Design Pressure	Increase SIT design pressure to 280 psig.	SL 1-24	No	No	Standard post-maintenance testing.	Not required.
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.	SL 1-24	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 (during outage 1-24)
Setpoints and Scaling: General	a. Replacement modifications will consist of compatible instrument replacements with increased operating ranges. b. Scaling changes, including: Main Steam instrumentation FW instrumentation Condensate instrumentation Heater Drain instrumentation Extraction Steam instrumentation c. Control systems setpoint changes (addressed below)	SL 1-24	No, for most items Yes, as identified below	No, for most items Yes, as identified below	Calibration.	All 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: • Main steam header pressure transmitters respanned • Steam flow transmitters respanned to accommodate higher steam flow • FW flow transmitters respanned to accommodate higher FW flow • FW pump pressure switches setpoints lowered.	SL 1-24	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.	SL 1-24	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 (during outage 1-24)
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.	SL 1-24	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	The FWCS will be changed to accommodate the increased feedwater flow at EPU conditions and the replacement SG flow control valves, which have an increased Cv. Additional changes will be made to improve post-trip SG level control.	SL 1-24	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 and Setpoint	RPS SG low level trip setpoint will be changed from 20.5% (narrow range) to 35%.	SL 1-24	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	85%	BOC	85% to 40% Ramp Change in Power at 0.5%/Min
31	40%	BOC	40% to 85% Ramp Change in Power at 0.5%/Min
32	100%	EOC	Reactor Trip

Table 2.12-4 (Continued)
NSSS Transients Evaluated for EPU with the CENTS Code

Case	Power Level	Cycle Time	Transient
33	100%	EOC	Turbine Trip/Reactor Trip
34	80%	BOC	Loss of One Reactor Coolant Pump
35	90%	BOC	90% to 60% Step Change in Load (alternate input)

2.13 Risk Evaluation

2.13.1 Regulatory Evaluation

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 of the proposed EPU confirms that no special circumstances exist.

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, 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 RS-001 (Reference 5) and its attachments.

Current Licensing Basis

The Level 1 PRA Model was initially developed in response to NRC Generic Letter (GL) 88-20, Individual Plant Examination (IPE) (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 and 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 Category Capability 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 1 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, 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 (Reference 10). FPL found no seismic vulnerabilities to potential severe accidents. This observation is equally applicable to St. Lucie Unit 1.

The fire portion of the IPE for External Events (IPEEE) 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, although the St. Lucie Unit 1 is not an SRP plant, it 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 presented in this Licensing Report (LR) Section are used to provide insight and to illustrate how FPL has integrated risk insights into the EPU.

The EPU proposes to increase core power from 2700 MWt to 3020 MWt. The 3020 MWt total includes a 10% increase in rated thermal power (RTP) and a 1.7% increase due to measurement uncertainty recapture (MUR) as described in LR Section 1.0, Introduction to the St. Lucie Plant Unit 1 Extended Power Uprate Licensing Report.

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 be risk-beneficial. 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, Table 1.0-1.

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)
- Core damage frequency and large early release frequency

This section evaluates the impact of the EPU on plant risk. The evaluation includes a review of plant risks associated with plant internal events, internal flood, fire, seismic, external flood, turbine missile generation, 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 internal events evaluation uses results from a current PRA model for both baseline and EPU. The baseline model reflects an EPU update which was undertaken to resolve observations identified in past St. Lucie Unit 1 PRA peer reviews and to bring the model into 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 PRA 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. While St. Lucie Unit 1 is not licensed to the SRP, in the process of resolution of the external event risk following EPU, the EPU plant was related to SRP standards.

LR Section 2.13.2.11 discusses the PRA benefits of past peer review generated F&Os.

2.13.2.2 St. Lucie Unit 1 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 31). Fault trees, comprised of component and human failure events, are developed for each of the systems identified in the top logic. The exceptions are the main feedwater (MFW) system and the reactor protection system (RPS). Although these systems include dependencies with other systems (e.g., electric power), the hardware is modeled at a higher level with a few representative basic events (e.g., MFW pumps fail to run).

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 12). 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 13). Data updates were prepared in accordance with ASME Standard Capability Category II (Reference 35).

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 24), design basis and other analyses to support development of success criteria. MAAP analyses were conducted in accordance with guidance contained in Reference 34. (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 14) and TR-100259 (Reference 15). The second approach was to apply the cause-based decision tree methodology (CBDTM), also developed by EPRI and documented in Reference 15. In both approaches, the probability of failure encompassed two contributions:

- The cognitive portion, which accounts for errors in detection, diagnosis, or decision-making
- 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 25). 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 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 16).

The PORV challenge frequency resulting from a reactor trip initiator is conservatively estimated at 0.00881 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% resulted in a CDF increase of 1×10^{-9} per year. LERF values remained unchanged.

The current PORV LOCA is classified as a small break LOCA, which means feedwater is required to remove decay heat. As the decay heat is greater for EPU, the small break LOCA assignment would remain.

2.13.2.3.1.3 Reactor Coolant Pump 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. While the LOCA break sizes and classifications used for the event classes will change (based upon the EPU MAAP runs) the impact on LOCA frequencies and on the PRA is negligible.

2.13.2.3.2 Steam Generator Tube Rupture (SGTR)

FPL installed replacement steam generators (SGs) in 1998. The SGs tubes are constructed of Alloy 690 material, which is less susceptible to stress corrosion cracking (SCC) effects. Core exit temperature changes from current to EPU conditions are relatively small and are within the expected design range for Alloy 690. As changes to SG operating conditions 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 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. 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 baseline EPU PRA calculation presented in LR Section 2.13.2.9 assumes a doubling of the current plant reactor trip frequency following 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 service and cooling water failures, among others. As discussed in LR Section 2.13.2.3.1, transient events that challenge the PORVs or results 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. EPU does not necessitate replacement or modification of any switchyard breakers or 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 is also expected to 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 EPU and weather induced LOOP events, no change in the weather induced LOOP frequency is expected.

It is possible that the unanticipated loss of some circuits may increase load on the remaining circuits to unacceptable levels. 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 a control element assembly (CEA) mechanically binds prior to significant insertion. As a consequence of the inability to shut down, 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 17). Reference 17 states the following:

“All active valves in the C-E-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.”

For purposes of PRA, analyses conservatively assume that should the RCS pressurize 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 1 analyses indicate that the EPU ATWS frequency is approximately 3.4E-07 per year. This results in a ΔCDF of less than 4.73E-08 per year. No changes were noted in the ATWS contribution to LERF. While EPU ATWS events do increase slightly, their significance is low due to the 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 18) of turbine missile generation has been performed for the BB281-13.9m2 retrofit design low pressure (LP) turbines that are being installed for EPU. Results of the analysis show that the missile generation frequencies remain below the NRC limits of 1E-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 19). 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 item 28 of 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

GL 88-20, Supplement No. 4 (Reference 20), requested each licensee to conduct an IPEEE 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 IPEEE SER (Reference 21) 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
- Equipment cooling (ultimate heat sink) requirements via the component cooling water (CCW) and intake cooling water (ICW) systems

EPU systems modifications were reviewed for their impact on safe shutdown. Through the review, it was concluded that none of the planned EPU plant modifications have any significant potential impact on seismic vulnerability. Therefore, the 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 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 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 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 1, the OBE is 0.05g and the DBE is assessed at 0.1g. Using NUREG-1488 (Reference 22), the frequency of a seismic event in the OBE to DBE range is 0.85E-04 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 based on uncertainties in equipment survival.

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, turbine plant cooling water, and the treated water storage tank (TWST). This evaluation indicated that both current and EPU CDF estimates were very close to 9E-08 per year. Similarly, LERF estimates were on the order of 1.3E-08. EPU impacts on seismic CDF and LERF estimates were judged to be 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 EPU on seismic risk is considered negligible.

2.13.2.4.2 Fire

A qualitative evaluation of EPU modifications was performed with respect to fire risk. The evaluation included an assessment of the impact of EPU on the initial IPEEE fire screening, and a reassessment of the three non-screened fire areas: main control room, cable spreading room and switchgear room. The impact of EPU changes on the FIVE screening was qualitatively evaluated. To better understand the fire impact of the planned changes, NUREG/CR-6850 (Reference 32) modeling guidance was used. The evaluation concluded that EPU changes would not impact the initial plant fire screening. It was further concluded that the combined CDF of the FIVE screened compartments was less than1E-05 per year. Results of a fire risk assessment of the remaining non-screened fire compartments indicate the fire risks are expected to be well below the risks identified in the IPEEE.

The combined fire risk estimates for the main control room, cable spreading room, and switchgear room are on the order of 4E-06 per year for each room. An assessment of the impact of planned EPU changes on the fire risk for these compartments indicates the impact to be negligible as 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 GL 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

St. Lucie Unit 1 is not an SRP plant; however, the IPEEE evaluated the risk impact of high winds, including hurricanes and tornadoes, and concluded that the design either conforms to the SRP criteria, or it has been demonstrated that where the design does not conform, the hazard frequency is acceptably low.

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 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 1, 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 current design meets the RG 1.59 (Reference 23) and SRP criteria, and thus, pose 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 1 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 EPU.

2.13.2.4.5 Quantitative Assessment for Non-Seismic External Events

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 EPU was examined as a part of the sensitivity analysis. This provides a gross estimate on the impact 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 0.00528 per year) with offsite 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.

2.13.2.5 Shutdown Operations Risk

FPL has reviewed the effects of EPU on the shutdown cooling (SDC) system (LR Section 2.8.4.4). The review adequately accounted for the effects of 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 EPU's impact on time available for operator actions, no further impact of 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 and fuel pool cooling; with adequate redundancy and contingency. At the higher thermal power of 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 EPU would not adversely impact safety consequences. As the shutdown operation related procedures are condition driven, no significant risk impacts to the shutdown operations procedures are anticipated for EPU. 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 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 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 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 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 EPU that affect pressure control success criteria. 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 EPU results in a more rapid depletion of inventory in the SG and degrades the OTC heat removal capability. By increasing the SG low level reactor trip setpoint and other operational changes (see below) for 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 83 minutes for current plant operation to 98 minutes for EPU operation. 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 decreased. As a result of changes in plant emergency response strategy to include a step to trip all 4 RCPs early in the event following identification of a TLOFW event, the equivalent time to avert core damage by restoring feedwater flow is also increased. For TLOFW events initiating at reactor trip, the predicted time to avert core damage is increased from 139 minutes to 145 minutes. (Note, without this change, the EPU would result in a reduction of operator action time to 120 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 SG low level reactor trip setpoint from 20.5% to 35%, and
2. Modify Emergency Operating Procedure (EOP) 1-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).

The intent of these actions is to increase the inventory in the SG following TLOFW events to increase the time available for the operator to implement OTC. Results from the MAAP analyses presented in LR Table 2.13-3 show that implementation of these actions following a TLOFW event with a reactor trip on SG low level will increase the time to successfully implement OTC from the current 30 minutes to 37 minutes at EPU. These changes also provide an additional

15 minutes for the plant staff to restore FW. In addition, to reduce the potential for AFW unavailability during an event, St. Lucie Unit 1 is modifying surveillance procedures to reduce potential pre-initiator human failure events associated with mis-positioning of the AFW system discharge valves. Combined, these EPU plant improvements have been shown to provide a significant safety benefit. Additional discussion of the impact of the above changes on the calculated PRA HEPs is provided in LR Section 2.13.2.6.3.3.

Additionally, 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. EPU does not significantly increase the likelihood of boron precipitation; however, simultaneous hot side/cold side injection flowrates will be increased to accommodate the higher decay heat.

Post-LOCA 10 CFR 50, Appendix K evaluations of EPU conditions indicate that the time to reach the solubility limit for boron in the core during some large and intermediate sized LOCAs is reduced from 10 hours to 6.5 hours. Reaching the solubility limit within the core can result in boron precipitation in the fuel assemblies which will reduce heat transfer rates and lead to core damage. As a result of EPU implementation, EOPs currently instruct operators to re-establish hot leg/cold leg SI no later than six hours after the initiation of SI in the cold leg to prevent boric acid precipitation.

There are no changes to the predicted HEPs and the risk impact of the above mentioned change is negligible, because this is a low probability event, the operators are well trained, and the required actions take place over a longer time frame.

Emergency core cooling system (ECCS) design changes for increased safety injection tank (SIT) pressure and increased hot leg injection flowrates have been explicitly included in the ECCS performance analyses and changes will not result in a change in LOCA success criteria.

The number of components required to support at-power RCS and core heat removal using MFW will not change for 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 program will change for EPU. Currently, the pressurizer level varies from 33.09% at 15% power to 65.6% at 100% power. After EPU, the pressurizer level will be 33.09% at 15% power, reach 65.6% at approximately 90% power and maintain that level through 100% power. To compensate for potential increases in PORV/SRV challenges, changes have been made to the quick response steam relief capacity. Realistic plant response analyses indicate that following EPU, PORV challenges will not occur 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 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 24) 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 2%. In some instances, lower core damage temperatures were conservatively applied. MAAP analyses confirm that one of the main impacts of EPU is a reduction in the time available for operator response due to the increased decay heat. The PRA includes more than 70 post-trip human actions; approximately half of these actions had reduced operator response times as a result of EPU. However, as most actions have ample time for operator response, in addition to the actions being well defined and procedure driven, fewer than ten of these human actions resulted in HEPs that were impacted by 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 EPU.

For transients not 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 break 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 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 2 PORVs and 2 SRVs. These results would be expected to be conservative for St. Lucie Unit 1.

Human actions that are impacted by EPU fall into two broad categories: inventory control and decay heat removal, as discussed below.

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 EPU. 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 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, 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.

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 HPSI.

At St. Lucie Unit 1, 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.

The time to restore cooling on a total loss of decay heat removal varies considerably based on the amount of water in the SG at the time of the trip and the status of the RCPs. Although the RCPs increase the rate of heat transfer to the SGs, the RCPs become a liability later in the LOCA event when the additional heat added by the RCPs (approx. 14 MWt) become a significant fraction of the decay heat. Accordingly, the EOPs will be modified for EPU to direct the operator to trip all RCPs early as a part of 1-EOP-01 SPTAs following initial identification of a TLOFW. This action extends SG inventory and provides an increased response window for operators to mitigate a TLOFW event via OTC.

Long Term Heat Removal

Long term 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 (see LR Section 2.13.2.6.3).

For large break LOCA scenarios, it is predicted that the required time for the operator to complete switchover into the simultaneous hot leg/cold leg injection mode will be shortened. This reduction in time was considered in developing the operator action for initiating hot leg injection. Based on the HRA evaluation, operator recovery times from the point of the cue to enter hot leg injection are unchanged, thus HEPs remain unchanged and impact on the plant risk is negligible.

2.13.2.6.3 Operator Actions

The higher decay heat level associated with 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 or even fail the action for insufficient available time. Compensatory changes to the SG low-level reactor trip setpoint and 1-EOP-01 SPTAs have been made to adequately offset these anticipated reductions.

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 with 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 25).

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 HEPs 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 human failures are included in the top cutsets. As a result, the surveillance frequency was increased on selected valves resulting in a risk-significant decrease in CDF and LERF.

2.13.2.6.3.3 Results of Human Reliability Analysis

Results of the HRA assessment are provided in LR Tables 2.13-4 and 2.13-5. 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 HEPs and the calculation methodology used. LR Table 2.13-5 illustrates the same actions as LR Table 2.13-4, but focuses on the percentage change in recovery times from the current to EPU operation and the consequences of failure to take the action.

For approximately one half of the operator actions included in the PRA, EPU has no impact on the estimated operator recovery actions.

As discussed in LR Section 2.13.2.6.2, human actions that are impacted by 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 the majority of these events, the reduction in the time available was not sufficient to cause a significant impact.

As can be seen from an examination of LR Table 2.13-5, in several instances the change to the SG low-level setpoint resulted in a significant benefit in the associated HEP. The increased time window improves the reliability of three basic operator actions following an instantaneous TLOFW: (1) restoration of MFW, (2) restoration of AFW and (3) implementation of OTC.

Following a loss of feedwater event, the differences in operator responses between the current and EPU decay heat removal scenarios are driven by the following factors:

- The plant decay heat level.
- The change in the SG-low-level reactor trip setpoint from 20.5% NR (current) to 35%NR (EPU).
- The changes to 1-EOP-01 which require all four reactor coolant pumps to be tripped upon identification of a total loss of feedwater scenario.

As discussed in LR Section 2.13.2.6.1.3, the net impact of the above changes is to extend the time for the event to reach a core uncovery or core damage condition. These changes extend the time for the operator for restore feed to the SG following a TLOFW event. However, this benefit is not fully realized for OTC actions, as the time for the plant to reach the 15% wide range level cue for operator action is also extended. As can be seen in LR Tables 2.13-4 and 2.13-5, the net impact is for the operator to have a reduced time window to take action to enter OTC for those sequences where a TLOFW event relies on a SG Low-Level reactor trip (see GHFPOTCTLL). A similar behavior is noted for delayed TLOFW events. For these events no credit is realized from an SG low-level trip or an early RCP trip as these events have already occurred prior to the onset of the TLOFW (see for example GHFPOTCTGT41). Consequently, HEPs for these once-through cooling scenarios are increased.

An assessment of the net risk impact of the current plant and EPU HRA was performed. This analysis consisted of estimating the plant risks as monitored by CDF and LERF. Results of these analyses indicate that by implementing a revised risk-informed TLOFW response strategy the decay heat impact on EPU HEPs is limited to a 6.67E-08 per year impact on CDF and 1.27E-08 impact on LERF.

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 EPU. Additionally, through trending, these programs will also identify deviations or potential increases in component failure rates. In some instances, EPU may require more frequent maintenance or replacement of components, to ensure proper system performance.

FPL utilizes an aggressive 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 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 2.13-6 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 2.13-6, EPU operation will be a lower risk from the current plant conditions. This risk decrease is due to the following:

- FPL implemented requirement for weekly surveillance on selected risk-significant valves to ensure proper alignment.
- Increase in the SG low level reactor trip set point from 20.5% to 35% NR.
- Change in 1-EOP-01 to include a requirement that all RCPs be tripped upon identification of a total loss of feedwater event.

LR Table 2.13-7 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 EPU to increase above its current risk contribution. Overall, EPU has a small impact on the CDF risk profile.

The above results reflect quantification of the PRA at a 9.0E-13 truncation limit. This value provides sufficient resolution for the risk calculations used for EPU. This is based on truncation sensitivity analysis results that indicate a total estimated difference of less than 3% for CDF and LERF between the 9.0E-13 truncation results and the 1E-11 truncation results.

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 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, the load on the lines from the generator to the switchyard and beyond will increase. For this reason, the sensitivity of line/grid loses 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 MFW system to increase operational margin and to reduce the susceptibility to reactor and turbine trips. These changes have been credited within the sensitivity study.

Increased Power - While the design has taken considerable effort to improve the feedwater controller to minimize the potential for PORV challenges, and that 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 2.13-8 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 EPU initiating event frequencies increase. This assumption was made to support internal events analyses, as described in LR Section 2.13.2.3.

Note that in the above table, changes are referenced to the EPU condition with the lower frequency. Referencing changes to the current plant can be established by adding the above risk changes to the ΔCDF and ΔLERF from LR Table 2.13-6. When referenced to the current plant, the combined impact of the above sensitivities would result in a ΔCDF of -2.77E-07 per year and a ΔLERF of -6.95E-08 per year.

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 5.96E-06 per year. Results of using the EPU HRA in the current PRA model are illustrated in LR Table 2.13-9. The HEPs used in the analysis can be found in LR Table 2.13-4.

2.13.2.9.3 Hardware Failure Likelihood and Unavailability

For the purpose of this sensitivity study, system component unreliability is increased by 10%, which is an approximate proportionality to the EPU. LR Table 2.13-10 provides a listing of Fussell Vesely (FV)-ranked SSC active elements whose failure probability was increased by 10%. These results indicate that a 10% increase in component unreliability will increase the EPU CDF by

2.85E-07 per year and the LERF by 2.02E-09 per year. When referenced to the current plant, the combined impact of the above sensitivities would result in a ΔCDF of -7.44E-08 per year and a ΔLERF of -6.21E-08 per year.

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 mention 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%. 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 or a main steam line break (MSLB) will increase the plant CDF by 5.7E-9 and LERF by 7.6 E-10. When referenced to the current plant, the combined impact of the above sensitivities would result in a ΔCDF of -3.54E-07 per year and a ΔLERF of -8.18E-08 per year.

Similarly, spurious MSIV closure frequency is estimated to reduce CDF by 1E-09 per year (and 3E-11 for LERF).

LR Table 2.13-11 illustrates the potential impact of changes in steam and feedwater system flowrates on increased pipe failure frequency and plant risk.

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 50% increase in pressurizer PORV challenge frequency was assumed for added conservatism. However, this magnitude of an increase is unlikely as several EPU improvements are being implemented to limit PORV/SRV challenges. Thus, any impact of EPU on PORV challenge risks is judged to be small.

Increasing the size and response of the steam bypass control system (SBCS) is intended to minimize potential MSSV challenges. Based on the expected EPU system design, post trip MSSV challenges are expected to be less likely than for the current plant. Therefore, this feature has not been credited in the EPU Level 2 model.

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 1, 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 2 standard PORVs, 2 SRVs and a bounding MTC curve. In reality, St. Lucie Unit 1 utilizes 3 SRVs; however, modeling only 2 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 ZZ1MTCUNF probability was changed from 2.20E-01 to 2.55E-01. The resulting increase in CDF becomes 4.73E-08 per year. As this event is treated conservatively in the PRA, the risk will not significantly impact the overall plant CDF. Additionally, no LERF impact is predicted. Therefore, regardless of the reference point used, the risk impact of 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 4 specific plant modifications. These are:

- Improved turbine cooling capacity
- Improved electrical bus margin
- Switchyard modifications
- 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 will be improved by 2.5%. In order to evaluate the risk impact of this improvement, failure probability of the dominant events associated with TCW system were reduced by 2.5%. LR Table 2.13-12 provides a listing of the TCW events whose failure probability was reduced by 2.5%.

Results of the CAFTA evaluation indicate that the TCW system improvements result in a negligible decrease in 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 IPB cooling systems that increase the normal operating margin for the associated bus. Additionally, the modification includes the shedding of non-essential loads upon an accident condition. This modification is judged to improve loss-of-offsite power related to plant-centered loads by at least 50%. Therefore, plant centered loss-of-offsite power initiating event frequency was reduced from 0.034 per year to 0.017 per year under EPU conditions.

At the reduced frequency level, the St. Lucie Unit 1 centered LOOP frequency used in the sensitivity study evaluation is still approximately 25% higher than the frequency identified in NUREG/CR-6890, Volume 1, Table 3-5. Accordingly, the results of the conservative CAFTA evaluation indicate that the improvements to cooling capacity of the TCW result in a decrease in CDF and LERF of 2.42E-07 and 3.97E-08 per year, respectively.

As a result of plant changes to the electrical system the potential for consequential LOOP are expected to decrease. Furthermore, since the probability of consequential LOOPs on reactor or turbine trips are typically on the order of 0.002-0.003, the net contribution of these events would be reasonably bounded by 10% of the plant centered LOOP frequency. Thus, no additional study in this area was considered necessary.

2.13.2.9.6.3 Impact of Increase in LOOP Due to Switchyard Modifications

Plant modifications proposed for EPU do not include modifications to the switchyard to cope with the increased power uprate. 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 1 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%. The results of the sensitivity study are presented in Table 2.13-13. Increasing all LOOP initiating event frequency values by 10% results in a plant CDF increase of 7.34 E-08 and LERF increase of 1.13E-08 per year (see also LR Table 2.13-8).

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 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 evaluated to reduce CDF by 5.5E-07 per year and LERF by approximately 1.E-07 per year.

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 2.13-14. The implementation of EPU is expected to be overall risk-beneficial at St. Lucie Unit 1. Although there are risk increases associated with some aspects of 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% to 35% NR.

- Change in EOPs to require that all RCPs are tripped upon identification of a TLOFW event in 1-EOP-01 SPTAs.
- 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 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.

- MFW pump replacement
- MSIV actuator upgrade
- SBCS capacity increase
- DEH computer replacement
- TCW HX replacement
- Electrical bus margin improvement
- IPB duct cooling upgrade
- 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, design basis plant risk changes to be considered "very small" (i.e., reside in Region III) should they not result in risk increases above 1×10^{-6} per year CDF and 1×10^{-7} 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 1×10^{-5} per year CDF and 1×10^{-6} per year LERF. The present evaluation concludes that EPU operation will have, in aggregate, a lower risk of plant operation than does the current plant.

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 involved an overall update of the PRA to Capability Category II of the ASME standard as well as an 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 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 26). The resulting F&Os of the CEOG peer review were published in February 2003 publication WCAP-16034, Rev 0, *St. Lucie Unit 1 and 2: Probabilistic Risk Assessment Peer Review Report, CEOG Task 1037,* (Reference 27). The peer review identified 10 A level F&Os and 34 B level F&Os.

Additionally, in July 2009, a focused peer review was conducted for LERF and the common cause failures (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.

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 A*

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 (SPF) HXs (2900 gpm), let down 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 SPF will act to moderate temperature changes due to the large volume of water.

Not only will the peak containment temperature and pressures will 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 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.

Resolution: The issues identified by the F&O were reviewed and resolved per St. Lucie Unit 1 engineering calculations. PRA model changes were made accordingly.

2. *Accident Sequence AS-14 Level of Significance A*

Peer Review Observation: The top 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 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 CS, LPSI, and 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, low pressure safety injection (LPSI), containment spray (CS)), and thus, recirculation flow paths, are tested within a week or so of each other. The 3-month exposure was reduced accordingly.

3. *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.

4. *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 S/G 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 (ADVs) 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.

5. *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. The may be some events (e.g., 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 S/G, 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.

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-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 cycle the AFW system will undergo. Further, the common cause MOV demand failure rate does 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 auxiliary feedwater actuation system (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.

9. 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 AFAS system appears to control the based on the NR SG water level (opens at 19% decreasing) closes at 29% NR. There is no calculation available to determine the number of cycles required for automatic flow control. Additionally the consequence of SG 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 was established. This information was considered in the updated PRA.

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-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.

12. 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 addition make-up must be modeled through the emergency sump or Chemical and Volume Control System (CVCS).

Resolution: Per 1-EOP-03 step 51 and 2-EOP-03 step 52, shutdown cooling would be initiated at pressurizer level greater than or equal to 30%, which is above the bottom of the hot leg.

13. 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 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.

14. 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 ft^3/lbm) to 100 psia at 300°F (0.01766 ft^3/lbm). Given RCS liquid volume of 10,400 ft^3, 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 EPU risk assessment.

15. 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 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.

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 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 CC analysis.

An evaluation or analysis to justify the exclusion of other electrical components (breakers, relays, inverters, MCC's, 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, 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 (WCAP- 16672-P, *Common Cause Failure parameter Estimates for the PWROG*) (Reference 28).

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 EXEL spreadsheet for HRAs provides the stress level selection and some 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. <u>Human Reliability HR-3 Level of Significance B</u>

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 a 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. <u>Human Reliability HR-5 Level of Significance B</u>

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% value above 1.0. 95% 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. <u>Human Reliability HR-6 Level of Significance B</u>

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 1 operating procedures are event-based. Unlike symptom-based procedures, to be found in WOG and GE 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 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 1 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 uses events (up to 12/2008) and associated industry references such as NUREG/CR-6890 and EPRI published documentation on LOOP.

29. Initiating Event IE-4 Level of Significance B

Peer Review Observation: St. Lucie includes loss of individual 120VAC instrument buses as initiators, but does not address multiple bus failures as initiators. The 120VAC buses power the RPS/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 EPU risk.

30. Initiating Event IE-5 Level of Significance B

Peer Review Observation: St. Lucie Unit 1 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. <u>Containment Performance L2-1 Level of Significance B</u>

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 SGTR 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. <u>Containment Performance L2-2 Level of Significance B</u>

Peer Review Observation: According to the St. Lucie Units 1 & 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% mass fraction of CsI (volatile) and Tellurium (non-volatile), Medium (or moderate) release is between 1% - 10% mass fraction of CsI and Tellurium, and Low as < 1% 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. <u>Containment Performance L2-3 Level of Significance B</u>

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 base 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 1 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 affects 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. <u>System Analysis SY-14 Level of Significance B</u>

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. <u>System Analysis SY-15 Level of Significance B</u>

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. <u>Thermal Hydraulic Analysis TH-2 Level of Significance B</u>

Peer Review Observation: FPL uses a combination of FSAR 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. <u>Thermal Hydraulic Analysis TH-Del3 Level of Significance B</u>

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 1 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 conform to the requirements of RG 1.200. This 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, in the EOP/AOPs 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 24). 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 are based on results of Appendix K calculations. Long term cooling for medium and large break LOCAs include the design basis results of the BORON (Reference 29) computer code. ATWS events are based on short term generic CE PWR CENTS (Reference 29) (CE Nuclear Transient Simulator) evaluations for similar CE PWRs.

2.13.2.12.1.1 Modular Accident Analysis Program (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 34. 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 uncovery 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 30) models the transient simulation of a CE PWR. The code is not intended to be used in conditions of significant core uncovery. 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 Computer Aided Fault Tree Analysis (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 31) are available on the Electric Power Research Institute (EPRI) website.

2.13.2.12.3 HRA Calculator

The HRA Calculator Software, Version 4.1: Human Reliability Analysis (Reference 25) 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 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 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 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 3.6E-07 per year and LERF is predicted to decrease by 8.2E-08 per year, i.e., be risk beneficial. 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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2. St. Lucie Units 1 & 2 Individual Plant Examination Submittal, December 1994.

3. Regulatory Guide (RG) 1.200, Revision 1, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, NRC, January 2007.

4. NRC Regulatory Guide 1.174, Rev. 1, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, November 2002.

5. RS-001, Review Standard for Extended Power Uprates, USNRC, December 2003.

6. GL 88-20, Individual Plant Examination for Severe Accident Vulnerabilities-10 CFR 50.54(f), D. Crutchfield (NRC), November 23, 1988.

7. NUREG-1407, Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, June 1991.

8. FPL Letter L-95-58, February 17, 1995.

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.

10. FPL Letter L-91-336, Response to Generic Letter 88-20 Supplement 4, to NRC, December 23, 1991.

11. EPRI TR-100370, Fire-Induced Vulnerability Evaluation (FIVE), April 1992.

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13. Final Report on the August 14, 2003 Blackout in United States and Canada: Causes and Recommendations, US-Canada Power System Outage Task Force, April 2004.

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16. EPRI NP-2230 - Frequency of Anticipated Transients, S. McClymont and B. W. Poehlman, ATWS: A Reappraisal, Part 3: January 1982.

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19. NUREG-1048 Appendix U, Table U1.

20. Generic Letter 88-20, Supplement 4, Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, NRC, June 28, 1991.

21. Individual Plant Examination of External Events for St. Lucie Units 1 and 2, December 1994.

22. NUREG-1488, Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains, USNRC, April 1994.

23. Regulatory Guide 1.59, Revision 2, Design Basis Floods for Nuclear Power Plants, August 1977.

24. Electric Power Research institute, Modular Accident Analysis Program, Version 4.0.7, September 2007.

25. Electric Power Research institute, Human Reliability Analysis Calculation, Version 4.1, November 2009.

26. NEI-00-02, Revision 3A, Probabilistic Risk Assessment (PRA) Peer Review Process Guidance, Nuclear Energy Institute, March 2000.

27. WCAP-16034, Revision 00, CEOG Task 1037, St. Lucie Units 1 and 2: Probabilistic Risk Assessment Peer Review Report, (also known as “NEI Peer Review for PSL”), Westinghouse, February 2003.

28. WCAP-16672-P, Revision 1, Common Cause Failure parameter Estimates for the PWROG, June 2008.

29. CENPD-254-P-A, Rev. 0, Post-LOCA Long Term Cooling Evaluation Model, June 1980.

30. WCAP-15996-NP-A, Rev. 1, Technical Description Manual for the CENTS Code, March 2005.

31. EPRI, CAFTA: Fault Tree Analysis System, Version 5.4, January 2009.

32. NUREG/CR-6850, EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities.

33. NUREG/CR-6268, Common Cause Failure Database and Analysis System, Vol. 1-4; June 1998.

34. EPRI TR 1015104, MAAP Applications Guide, November 2007.

35. American Society for Mechanical Engineers, ASME Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME-RA-Sb-2005, ASME, 2005

Table 2.13-1
Impact of EPU on Other External Event Risks

Hazard	Evaluation	Potential Impact of 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 SI. Lucie Units 1 and 2	None
Seiche	Minimal plant impact	None
Snow	Hazard is not applicable to SI. Lucie Units 1 and 2	None
Soil shrink	Minimal impact	None
Volcanic activity	Hazard is not applicable to SI. Lucie Units 1 and 2	None

Table 2.13-2
Comparison of Pre- and Post-EPU External Event Risk

	CDF	ΔCDF CDF_{EPU}-$CDF_{Pre-EPUr}$	LERF	ΔLERF $LERF_{EPU}$-$LERF_{PreEPU}$
Current (per yr)	1.08E-06	N/A	1.88E-07	N/A
EPU (per yr)	1.08E-06	1.00E-09	1.87E-07	-9.6E-10

Table 2.13-3
Comparison of Current and EPU Plant Response to Total Loss of Feedwater Events

Basic Event ID	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	Comments(1)
LOMFW and AFW, reactor trip of SG low level (SG-LL) SG-LL: 20.5% (Current) SG-LL:35% (EPU)	83	54	98 (all RCPs tripped while in 1-EOP-01)	71 (all RCPs tripped while in 1-EOP-01)	Latest time to avert core damage via OTC: Current: 30 min EPU: 37 min
LOMFW resulting from a reactor trip (SG at nominal level) followed by loss of all AFW (trip 2, leave 2 RCP strategy)	139	100	145 (all RCPs tripped at 5 minutes)	113 (all RCPs tripped at 5 minutes)	Latest time(2) to avert core damage via OTC: Current:75 min EPU: 75 min

1. Success criteria timings based on 2 PORVs, 2 high pressure safety injection (HPSIs) and 2 charging pumps. Increasing success criteria requirements to 3 charging pumps increases the time to implement OTC to 45 minutes (current plant) or 48 minutes (EPU).
2. Success criteria timings based on 2 PORVs, 2 HPSIs. Reducing success criteria requirements to 2 PORVs, 1 HPSI will shorten operator action time to 45 minutes.

Table 2.13-4
Comparison of Current and EPU Plant Human Error Probability

Basic Event ID	Basic Event Description	HRA Method	Baseline HEP	EPU HEP	Baseline Recovery Time (Minutes)	EPU Recovery Time (Minutes)
AHFPCSTMKUP	Fail provide long-term makeup to CST via TWST	CBDTM	8.70E-05	8.70E-05	691	595
AHFPMANUAL-L	Fail manually start AFW pump(s) (loss of auto start signal)	CBDTM	8.60E-05	8.60E-05	77	92
AHFPMANUAL-N	Fail start AFW pump(s) after loss of autostart signal	CBDTM	8.60E-05	8.60E-05	133	141
AHFPMANUAL-R	Fail start AFW pump(s) to feed SGs & loss auto start signal	CBDTM	7.80E-05	7.80E-05	379	294
AHFPMANUAL-S	Fail start AFW pump(s) after small break LOCA & no autostart signal	CBDTM	8.60E-05	8.60E-05	159	146
AHFPSGISO	Fail isolate faulted SG & realign AFW follow SGTR	CBDTM	2.20E-04	2.20E-04	176	146
AHFPSWU2CST	Fail to provide suction to U1 AFW from U2 CST	CBDTM	1.10E-03	1.10E-03	196	158
AHFPXCON	Fail to xtie AFW trains	CBDTM	3.10E-03	3.10E-03	74	89
AHFPXCON>4	Fail xtie AFW trains (trip@norm SG level & FW avail for >=4hrs)	CBDTM	2.60E-03	2.60E-03	409	304
AHFPXCON-L<4	Fail xtie AFW trains (trip on lo-SG level & 1st 4hrs-no FW)	CBDTM	3.10E-03	3.10E-03	74	89

Table 2.13-4 (Continued)
Comparison of Current and EPU Plant Human Error Probability

Basic Event ID	Basic Event Description	HRA Method	Baseline HEP	EPU HEP	Baseline Recovery Time (Minutes)	EPU Recovery Time (Minutes)
AHFPXCON-N<4	Fail xtie AFW trains (trip on norm-SG level & 1st 4hrs-no FW)	CBDTM	2.60E-03	2.60E-03	128	136
AHFRCPUMP	fail ctrl TD AFW pp during SBO & LODC	CBDTM	1.00E-01	1.00E-01	409	304
CHFPRCPTRP	Failure to trip RCPs loss of CCW	CBDTM	9.70E-04	9.70E-04	36	36
CHFPRCPTRP-L	Failure to locally trip RCPs loss of CCW and DC power	CBDTM	5.30E-03	5.30E-03	36	36
EHFP1XTIE	Failure to align blackout xtie to power Unit 1 from Unit 2	CBDTM	1.00E-03	1.00E-03	122	103
EHFPDC-1AB	Failure to realign 125vdc bus AB (not battery depletion)	CBDTM	2.30E-03	2.30E-03	77	92
EHFPEDGFO	Failure of manual MU to EDG day tank after auto MU fails	HCR/ORE	4.10E-02	4.10E-02	19	19
EHFRMANEDG	Failure to close EDG breaker w/loss of auto close permissive	CBDTM	9.70E-04	9.70E-04	124	132
EHFRRESET	Failure to recover offsite power following failure of lockout relay	CBDTM	2.40E-04	2.40E-04	133	141
FHFP1RECMFW	Failure to restore MFW after transient (trip on low SG level)	HCR/ORE	1.20E-02	4.70E-03	53	68

Table 2.13-4 (Continued)
Comparison of Current and EPU Plant Human Error Probability

Basic Event ID	Basic Event Description	HRA Method	Baseline HEP	EPU HEP	Baseline Recovery Time (Minutes)	EPU Recovery Time (Minutes)
FHFP1RECMFWI	Fail to restore MFW after small break LOCA/SGTR (norm SG level@trip)	HCR/ORE	4.90E-03	4.90E-03	120	120
FHFP1RECMFW-L	Failure to restore MFW after transient (trip on lo-SG level)	HCR/ORE	1.20E-02	4.70E-03	53	68
FHFP1RECMFW-N	Failure to restore MFW after transient (trip on normal SG level)	HCR/ORE	6.00E-04	6.00E-04	109	117
GHFPOTCR	Failure to initiate OTC following SGTR	HCR/ORE	5.00E-04	5.00E-04	89	23
GHFPOTCS	Failure to initiate OTC following small break LOCA	HCR/ORE	1.00E+00	1.00E+00	-40	-67
GHFPOTCTGT41	Fail to initiate OTC-FW for @least 4hrs (1 PORV)	CBDTM	3.60E-03	1.20E-02	21	13
GHFPOTCTGT42	Fail to initiate OTC-FW for @least 4hrs (2 PORV)	CBDTM	3.40E-04	1.10E-03	106	58
GHFPOTCTLL	Fail initiate OTC follow LOFW -lo SG lvl & no FW (1st 4hrs)	HCR/ORE	3.70E-03	1.70E-02	32.3	14.4
GHFPOTCTNL1	Fail initiate OTC -norm SG lvl trip & no FW-1st 4hrs (1HPSI pp)	HCR/ORE	5.10E-01	5.10E-01	0	0
GHFPOTCTNL2	Fail initiate OTC -normSG lvl trip & no FW-1st 4hrs (2HPSI pp)	CBDTM	3.60E-03	9.50E-04	29	34.3

Table 2.13-4 (Continued)
Comparison of Current and EPU Plant Human Error Probability

Basic Event ID	Basic Event Description	HRA Method	Baseline HEP	EPU HEP	Baseline Recovery Time (Minutes)	EPU Recovery Time (Minutes)
GHFPOTCTNLOG	Failure to initiate OTC (LOOP) -no FW 1st 4hrs	CBDTM	3.60E-03	9.50E-04	29	34.3
GHFPOTCTX1	Failure to initiate OTC -CST depletion (1 PORV)	HCR/ORE	1.10E-03	4.50E-03	52	19
GHFPOTCTX2	Failure to initiate OTC -CST depletion (2 PORV)	CBDTM	1.80E-04	3.40E-04	157	114
HHFPU1ALIGN	Failure to align IA compressor 1A/B after LOOP	CBDTM	1.40E-05	1.40E-05	421	325
HHFPU2ALIGN	Failure to align IA compressor 2A/B after LOOP	CBDTM	1.40E-05	1.40E-05	421	325
IHFP1ELEQ	Failure to restart elect equip room fans following LOOP	CBDTM	5.20E-03	5.20E-03	60	60
JHFP1HOTLEG	Failure to initiate hot-leg injection following lrg LOCA	CBDTM	5.60E-05	5.60E-05	215	215
JHFPMANIA	Failure to establish SDC following loss of IA	HCR/ORE	1.10E-03	1.20E-03	376	280
JHFPSDCR	Failure to establish SDC following SGTR	CBDTM	4.20E-06	5.20E-06	436	340
JHFPSDCS	Failure to establish SDC following small break LOCA	CBDTM	4.20E-06	4.20E-06	451	355
JHFPSDCT	Failure to establish SDC following transient	CBDTM	1.80E-05	1.80E-05	336	240
JHFPSDCW	Failure to establish SDC following ATWS	CBDTM	1.80E-05	1.80E-05	336	240

Table 2.13-4 (Continued)
Comparison of Current and EPU Plant Human Error Probability

Basic Event ID	Basic Event Description	HRA Method	Baseline HEP	EPU HEP	Baseline Recovery Time (Minutes)	EPU Recovery Time (Minutes)
LHFPMANUAL	Failure to initiate CS manually when auto actuation fails	CBDTM	1.90E-03	1.90E-03	54	54
MHFPEMBOR	Failure to perform emergency boration to shut down reactor	CBDTM	1.40E-02	1.40E-02	7	7
NHFPMANTRIP	Failure to trip reactor when auto scram fails	CBDTM	2.50E-03	2.50E-03	0.67	0.67
NHFPMANUALR	Fail initiate sump recirc after LOCA & auto switchover fails	HCR/ORE	2.20E-01	2.20E-01	0.6	0.6
NHFPMANUALS	Failure to actuate SI manually after small break LOCA	CBDTM	1.90E-03	1.90E-03	33	30
OHFPPORVISO	Failure to isolate PORV relief path after PORV fails open	CBDTM	6.50E-05	6.50E-05	142	140
OHFPPORVISOW	Failure to isolate PORV relief path after PORV fails open (ATWS)	CBDTM	1.10E-04	1.10E-04	142	140

Table 2.13-5
Comparison of Current and EPU Operator Recovery Times

Basic Event ID	Basic Event Description	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)	Change in Time Available(1)	Failure Consequence
AHFPCSTMKUP	Fail provide long-term makeup to CST via TWST	691	595	-14%	Insufficient CST level to sustain AFW absent makeup to the tank
AHFPMANUAL-L	Fail manually start AFW pump(s) (loss of auto start signal)	77	92	19%	Insufficient FW to SGs
AHFPMANUAL-N	Fail start AFW pump(s) after loss of autostart signal	133	141	6%	Insufficient FW to SGs
AHFPMANUAL-R	Fail start AFW pump(s) to feed SGs & loss auto start signal	379	294	-22%	Insufficient FW to SGs
AHFPMANUAL-S	Fail start AFW pump(s) after small break LOCA & no autostart signal	159	146	-8%	Insufficient FW to SGs
AHFPSGISO	Fail isolate faulted SG & realign AFW follow SGTR	176	146	-17%	Overfilling and carryover of water into main steam line. Assumed to fail AFW
AHFPSWU2CST	Fail to provide suction to U1 AFW from U2 CST	196	158	-19%	Insufficient FW to SGs
AHFPXCON	Fail to xtie AFW trains	74	89	20%	Insufficient FW to SGs
AHFPXCON>4	Fail xtie AFW trains (trip@norm SG level & FW avail for >=4hrs)	409	304	-26%	Insufficient FW to SGs
AHFPXCON-L<4	Fail xtie AFW trains (trip on lo-SG level & 1st 4hrs-no FW)	74	89	20%	Insufficient FW to SGs
AHFPXCON-N<4	Fail xtie AFW trains (trip on norm-SG level & 1st 4hrs-no FW)	128	136	6%	Insufficient FW to SGs
AHFRCPUMP	fail ctrl TD AFW pp during SBO & LODC	409	304	-26%	Loss of TD AFW

Table 2.13-5 (Continued)
Comparison of Current and EPU Operator Recovery Times

Basic Event ID	Basic Event Description	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)	Change in Time Available(1)	Failure Consequence
CHFPRCPTRP	Failure to trip RCPs loss of CCW	36	36	0%	Onset of RCP Seal LOCA
CHFPRCPTRP-L	Failure to locally trip RCPs loss of CCW and DC power	36	36	0%	Onset of RCP Seal LOCA
EHFP1XTIE	Failure to align blackout xtie to power Unit 1 from Unit 2	122	103	-16%	Failure to restore power
EHFPDC-1AB	Failure to realign 125vdc bus AB (not battery depletion)	77	92	19%	Failure to restore power
EHFPEDGFO	Failure of manual MU to EDG day tank after auto MU fails	19	19	0%	Failure of EDGs upon tank depletion
EHFRMANEDG	Failure to close EDG breaker w/loss of auto close permissive	124	132	6%	Failure of EDG due to overload
EHFRRESET	Failure to recover offsite power following failure of lockout relay	133	141	6%	Failure to restore power
FHFP1RECMFW	Failure to restore MFW after transient (trip on low SG level)	53	68	28%	MFW not available to feed SGs
FHFP1RECMFWI	Fail to restore MFW after small break LOCA/SGTR (norm SG level@trip)	120	120	0%	MFW not available to feed SGs
FHFP1RECMFW-L	Failure to restore MFW after transient (trip on lo-SG level)	53	68	28%	MFW not available to feed SGs
FHFP1RECMFW-N	Failure to restore MFW after transient (trip on normal SG level)	109	117	7%	MFW not available to feed SGs

Table 2.13-5 (Continued)
Comparison of Current and EPU Operator Recovery Times

Basic Event ID	Basic Event Description	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)	Change in Time Available(1)	Failure Consequence
GHFPOTCR	Failure to initiate OTC following SGTR	89	23	-74%	Core damage. Condition applied with loss of all FW for small SGTRs
GHFPOTCS	Failure to initiate OTC following small break LOCA	-40	-67	68%	Not viable operator action
GHFPOTCTGT41	Fail to initiate OTC-FW for @least 4hrs (1 PORV)	21	13	-38%	Minimal OTC strategy fails and GHFPOTCTGT42 pursued
GHFPOTCTGT42	Fail to initiate OTC-FW for @least 4hrs (2 PORV)	106	58	-45%	Core damage, provided FW not restored in timely manner
GHFPOTCTLL	Fail initiate OTC follow LOFW -lo SG lvl & no FW (1st 4hrs)	32.3	14.4	-55%	Core damage, provided FW not restored in timely manner
GHFPOTCTNL1	Fail initiate OTC -norm SG lvl trip & no FW-1st 4hrs (1HPSI pp)	0	0	NA	Minimal OTC strategy fails and GHFPOTCTNL2 pursued
GHFPOTCTNL2	Fail initiate OTC -normSG lvl trip & no FW-1st 4hrs (2HPSI pp)	29	34.3	18%	Core damage, provided FW not restored in timely manner
GHFPOTCTNLOG	Failure to initiate OTC (LOOP) -no FW 1st 4hrs	29	34.3	18%	Core damage, provided FW not restored in timely manner
GHFPOTCTX1	Failure to initiate OTC -CST depletion (1 PORV)	52	19	-63%	Minimal OTC strategy fails and GHFPOTCTX2 pursued
GHFPOTCTX2	Failure to initiate OTC -CST depletion (2 PORV)	157	114	-27%	Core damage, provided FW not restored in timely manner
HHFPU1ALIGN	Failure to align IA compressor 1A/B after LOOP	421	325	-23%	Loss o f instrument air.

Table 2.13-5 (Continued)
Comparison of Current and EPU Operator Recovery Times

Basic Event ID	Basic Event Description	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)	Change in Time Available(1)	Failure Consequence
HHFPU2ALIGN	Failure to align IA compressor 2A/B after LOOP	421	325	-23%	Loss of instrument air
IHFP1ELEQ	Failure to restart elect equip room fans following LOOP	60	60	0%	Insufficient CST level to sustain AFW absent makeup to the tank
JHFP1HOTLEG	Failure to initiate hot-leg injection following lrg LOCA	215	215	0%	Insufficient FW to SGs
JHFPMANIA	Failure to establish SDC following loss of IA	376	280	-26%	Insufficient FW to SGs
JHFPSDCR	Failure to establish SDC following SGTR	436	340	-22%	Insufficient FW to SGs
JHFPSDCS	Failure to establish SDC following small break LOCA	451	355	-21%	Insufficient FW to SGs
JHFPSDCT	Failure to establish SDC following transient	336	240	-29%	Overfilling and carryover of water into main steam line. Assumed to fail AFW
JHFPSDCW	Failure to establish SDC following ATWS	336	240	-29%	Insufficient FW to SGs
LHFPMANUAL	Failure to initiate CS manually when auto actuation fails	54	54	0%	Insufficient FW to SGs
MHFPEMBOR	Failure to perform emergency boration to shut down reactor	7	7	0%	Insufficient FW to SGs
NHFPMANTRIP	Failure to trip reactor when auto scram fails	0.67	0.67	0%	Insufficient FW to SGs

Table 2.13-5 (Continued)
Comparison of Current and EPU Operator Recovery Times

Basic Event ID	Basic Event Description	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)	Change in Time Available(1)	Failure Consequence
NHFPMANUALR	Fail initiate sump recirc after LOCA & auto switchover fails	0.6	0.6	0%	Insufficient FW to SGs
NHFPMANUALS	Failure to actuate SI manually after small break LOCA	33	30	-9%	Loss of TD AFW
OHFPPORVISO	Failure to isolate PORV relief path after PORV fails open	142	140	-1%	Onset of RCP Seal LOCA
OHFPPORVISOW	Failure to isolate PORV relief path after PORV fails open (ATWS)	142	140	-1%	Onset of RCP Seal LOCA

1. (EPU-CURRENT)/CURRENT*100

Table 2.13-6
Comparison of Current and EPU Internal Event Plant Risks

	CDF (per year)	∆CDF (per year)	LERF (per year)	∆LERF (per year)
Current	5.96E-06	N/A	4.06E-07	N/A
EPU	5.60E-06	-3.6E-07	3.23E-07	-8.23E-08

Table 2.13-7
Impact of Potential Initiating Event Frequency Changes on EPU CDF

Initiating Event (IE)	Current Plant (per year) % Contribution	Current Plant (per year) CDF per year Contribution	EPU (per year) % Contribution	EPU (per year) CDF per year Contribution
Small break LOCA	33%	1.98E-06	35%	2.10E-06
Large break LOCA	15%	9.23E-07	16%	9.82E-07
Loss of MFW	15%	9.21E-07	9%	5.26E-07
Loss of grid	13%	7.67E-07	13%	7.83E-07
Reactor/turbine trip	5%	2.77E-07	7%	4.21E-07
Reactor vessel rupture	5%	2.70E-07	5%	2.87E-07
Medium LOCA	3%	2.05E-07	4%	2.18E-07
Loss of DC bus	3%	1.81E-07	3%	1.83E-07
Loss of CCW/ICW	2%	1.22E-07	2%	1.29E-07
Other	2%	1.04E-07	2%	1.02E-07
SGTR	1%	8.83E-08	2%	9.31E-08
ISLOCA	1%	7.86E-08	1%	8.36E-08
Seal LOCA	1%	4.93E-08	1%	5.25E-08

Table 2.13-8
Sensitivity to Initiating Event Frequencies

Initiating Event (IE) Description	Base IE Frequency (per year)	IE Frequency Increase for EPU	EPU ∆CDF (per year)	EPU ∆LERF (per year)
Loss of offsite power	4.76E-02	10%	7.34E-08	1.13E-08
Loss of 4Kv and 6.9 Kv electrical bus	(1)	10%	2.02E-09	7.34E-10
Reactor trip (with concurrent PORV challenge)	8.81E-03	50%	1E-09	unchanged
Loss of MFW due to feedline break	3.33E-03	10%	2.1E-09	5E-10
Main steamline break	1.47E-03	10%	3.6E-09	2.6E-10
Spurious MSIV isolation signal	2.09E-02	10%	1E-09	3E-11
1. Support System initiating event (SSIE): SSIE is modeled via use of fault trees.				

Table 2.13-9
Sensitivity to Changes in Human Actions (Reduced HRA Timing)
Comparison of Current and EPU Plant Risks

	CDF	∆CDF	LERF	∆LERF
Current	5.96E-06	N/A	4.06E-07	N/A
EPU	6.03E-06	6.67E-08	4.18E-07	1.27E-08

Table 2.13-10
Component Unreliability Sensitivity Study

CAFTA Basic Event ID	Description	Probability	
		Current	EPU (10% Inc)
GMM1MRMOV	Minimum recirc line motor valves transfer closed	2.23E-04	2.46E-04
FMM1SGCVLV	Common cause failure of SG check valves FTO	2.72E-06	2.99E-06
ATPF1AFW1C	Turbine-driven pump AFW1C fails to run	1.09E-02	1.20E-02
QMM1BSCCF	PLUGGING failure of basket strainers SS-21-1A/B due to CCF	3.36E-05	3.70E-05
JMM1HCVFOH	LPSI injection valves fail open during hot leg inj-flow diversioN	2.76E-03	3.04E-03
AMM1PCFTS	AFW pump 1C fails to start	1.04E-02	1.14E-02
AMMCCPABS	Common cause failure (2/3) OF MD AFW pumps 1A & 1B to start	1.56E-04	1.71E-04
GMM1FTRCFI	Common cause failure of HPSI pumps to run during injection	3.64E-05	4.00E-05
FCVN109294	Check valve V09294 fails to open (TO 1B S/G)	1.00E-04	1.10E-04
FCVN109252	Check valve V09252 fails to open (TO 1A S/G)	1.00E-04	1.10E-04
AMMCCPABCS	Common cause failure (3/3) of AFW pumps 1A, 1B, & 1C to start	2.26E-06	2.49E-06
AMM1PBFTR	AFW pump 1B fails to run	2.07E-03	2.28E-03
AMM1SGAP1A	Modular event for header valves in flow-path from MTR pump 1A to SG 1A	3.60E-03	3.96E-03
AMM1PAFTR	AFW pump 1A fails to run	2.07E-03	2.28E-03
AMMCCPABCR	Common cause failure (3/3) of AFW pumps 1A 1B, & 1C to run	1.90E-06	2.09E-06
ATM1AFWP1B	AFW pump 1B train unavailable due to test/maintenance	2.32E-03	2.55E-03
QMM1HDRA	ICW hdr A strainer/isol valve failures	7.26E-04	7.98E-04
QMM1HDRB	ICW hdr B strainer/isol valve failures	7.26E-04	7.98E-04
GMM1PAFTRI	Failure of HPSI pump A to run during injection	1.23E-03	1.35E-03
AMMCHMVABCD	Common cause failure (4/4) header MOVs MV-09-09/10/11/12	1.69E-06	1.86E-06

Table 2.13-10 (Continued)
Component Unreliability Sensitivity Study

CAFTA Basic Event ID	Description	Probability	
		Current	EPU (10% Inc)
GMM1PBFTRI	Failure of HPSI pump B to run during injection	1.23E-03	1.35E-03
GMPA1PUMPA	HPSI pump A fails to start	1.06E-03	1.17E-03
GMPA1PUMPB	HPSI pump B fails to start	1.06E-03	1.17E-03
GMM1MPACCF	Common cause failure of HPSI pumps to start	1.97E-05	2.17E-05
EMMDGRABCD	CCF (4/4) of EDG 1A,1B, 2A, AND 2B to run	9.00E-05	9.90E-05
EDGR11BEDG	EDG 1B FTR	4.13E-02	4.54E-02
EDGR22AEDG	EDG 2A FTR	4.13E-02	4.54E-02
EDGR22BEDG	EDG 2B FTR	4.13E-02	4.54E-02
GMM1ASUMP	Local faults of ECCS pump A suction line from sump	4.25E-03	4.68E-03
AMPA1AFW1A	Motor-driven pump AFW1A fails to start	2.83E-03	3.11E-03
AMPA1AFW1B	Motor-driven pump AFW1B fails to start	2.83E-03	3.11E-03
GMM1BSUMP	Local faults of ECCS pump B suction line from sump	4.25E-03	4.68E-03
AMM1SGAP1A-4	Failure of hdr valves in flow-path from mtr pump 1A TO SG 1A – 4 HR mission	2.76E-03	3.04E-03
AMM1SGBP1B-4	Modular event for header valves in flow-path from mtr pump 1B TO SG 1B – 4 hr	2.76E-03	3.04E-03
QMM1MPACCF	ICW pump fails to start due to common cause failure	1.14E-05	1.25E-05
EDGR11AEDG	EDG 1A FTR	4.13E-02	4.54E-02
EMM1BFOSS	Independent failure of 1B EDG fuel oil supply system	1.66E-02	1.83E-02
EMM1AFOSS	Independent failures of 1A EDG fuel oil supply system	1.66E-02	1.83E-02
ATPF1AFW1C-4	Turbine-driven pump AFW1C fails to run – 4 hr	1.82E-03	2.00E-03
QMPS1ICWPB	ICW PP FTS	7.33E-04	8.06E-04
CMPS1CCWPB	Motor-driven CCW pump B fails to start	7.33E-04	8.06E-04

Table 2.13-10 (Continued)
Component Unreliability Sensitivity Study

CAFTA Basic Event ID	Description	Probability	
		Current	EPU (10% Inc)
AMM1SGBP1B>4	Modular event for header valves in flow-path from mtr pump 1B to SG 1B	8.46E-04	9.31E-04
GMM1SMVCCF	Common cause failure of sump outlet motor valves to open	9.37E-05	1.03E-04
EMM2AFOSS	Independent failures of 2A EDG fuel oil supply system	1.67E-02	1.83E-02
EMM2BFOSS	Independent failures of 2B EDG fuel oil supply system	1.67E-02	1.83E-02
ORYT1V1200	PZR safety valve V1200 fails to reseat	7.45E-03	8.20E-03
ORYT1V1201	PZR safety valve V1201 fails to reseat	7.45E-03	8.20E-03
ORYT1V1202	PZR safety valve V1202 fails to reseat	7.45E-03	8.20E-03
JMVL13480I	Motor operated valve V3480 leaks catastrophically (1 year exposure)	2.93E-05	3.22E-05
JMVL13652I	Motor operated valve V3652 leaks catastrophically (1 year exposure)	2.93E-05	3.22E-05

Table 2.13-11
Impact of Potential Increases in Initiating Event Frequency Changes on EPU CDF

Initiating Event (IE)	Description	Base IE Freq (per year)	IE Freq Increase for EPU	EPU CDF Delta (per year)	LERF Delta (per year)
%ZZT3DU1	Loss of MFW due to feedline break common to both MFW trains	1.11E-03	1.1		
%ZZT3DU1A	Loss of main feedwater due to feedline break on SG 1A	1.11E-03	1.1	2.1E-09	5E-10
%ZZT3DU1B	Loss of main feedwater due to feedline break on SG 1B	1.11E-03	1.1		
%ZZT5U1A	Steamline break upstream of SG 1A MSIV	3.15E-04	1.1		
%ZZT5U1B	Steamline break upstream of SG 1B MSIV	3.15E-04	1.1	3.6E-09	2.6E-10
%ZZT6U1	Steamline break downstream of the MSIVS	8.40E-04	1.1		
%ZZT7MSU1	Spurious main steam isolation signal	2.09E-02	1.1	1E-09	3E-11

Table 2.13-12
EPU Sensitivity to Improved Cooling Capacity of TCW
(Failure Rates Reduced by 2.5%)

Basic Event		Probability	
		Current	2.5% EPU Reduction
TMM1AFLOWE	Faults in pump flow path (1 yr exposure)	4.86E-02	4.74E-02
TMM1AFLOWL	Faults in pump flow path (MTTR)	4.09E-04	3.99E-04
TMM1AHX	Loss of ‘A’ TCW HX (1 year exposure)	1.98E-01	1.93E-01
TMM1AHXL	Loss of ‘A’ TCW HX (MTTR)	1.81E-03	1.77E-03
TMM1AICWE	Loss of ICW flow to ‘A’ TCW HX (1 yr exposure)	2.35E-01	2.30E-01
TMM1AICWL	Loss of ICW flow to ‘A’ TCW HX (MTTR)	2.20E-03	2.15E-03
TMM1BFLOWE	Faults in pump flow path (1 yr exposure)	4.86E-02	4.74E-02
TMM1BFLOWL	Faults in pump flow path (MTTR)	4.09E-04	3.99E-04
TMM1BHX	Loss of ‘B’ TCW HX (1 year exposure)	1.98E-01	1.93E-01
TMM1BHXL	Loss of ‘B’ TCW HX (MTTR)	1.81E-03	1.77E-03
TMM1BICWE	Loss of ICW flow to ‘B’ TCW HX (1 yr exposure)	2.35E-01	2.30E-01
TMM1BICWL	Loss of ICW flow to ‘B’ TCW HX (MTTR)	2.2E-03	2.15E-03

Table 2.13-13
Comparison of Increased LOOP
For Switchyard Modification Sensitivity Evaluation

CAFTA Basic Event		Frequency (yr^{-1}) Pre-EPU	10% Increase	NUREG/CR--6890, Vol 1, (Table 3-5)
%ZZ1LOGP	Loss offsite power (plant-centered)	3.40E-02	3.74E-02	1.31E-02
%ZZ1LOGG	Loss of offsite power (grid-related)	2.52E-03	2.77E-03	1.71E-03
%ZZ1LOGW	Loss of offsite power (weather-induced)	5.24E-03	5.76E-03	3.99E-03
%ZZ1LOGGBO	Loss of offsite power (grid-blackout)	5.84E-03	6.42E-03	Not Applicable

Table 2.13-14
Current/EPU Summary Evaluation

Model	Current		EPU		Change	
	CDF	LERF	CDF	LERF	CDF	LERF
Internal events	5.96E-06	4.06E-07	5.60E-06	3.23E-07	-3.6E-07	-8.23E-08
Internal flood	<5E-07	Not Available	<5E-07	Not available	<5 E-08	Very small
Fire (non-screened compartments)[(1),(2)]	<4 E-06	< 4E-07[(1)]	< 4E-06	< 4E-07[(1)]	Small impact possible	Small impact possible
Fire (screened compartments)[(1),(2)]	<1.0E-06	<1.0E-07[(1)]	<1.0E-06	<1.0E-07[(1)]	Small impact possible	Small impact possible
External events	1.08E-06	1.88E-07	1.08E-06	1.87E-07	1E-09	-1E-09
Seismic	9.07E-08	1.31E-08	9.19E-08	1.33E-08	1.25E-09	Negligible
Turbine missile	Not Assessed	Not Assessed	<<2.6E-06 (IE Value, not CDF)	Not Available	Negligible	Negligible
Shutdown	Existing procedures and process adequate. EPU should be adequately controlled by existing process. Minor modifications to procedures 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% of CDF.
2. IPEEE risks have been re-evaluated. Current risks consider severity factors below unity and credit potential actions of a fire brigade.

2.14 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 1 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 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 TLAAs 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 TLAAs for the upper shelf energy (USE), PTS, and pressure-temperature (P-T) limit curves.

Upper Shelf Energy

Appendix G to 10 CFR 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 1. The NRC determined that the 60-year USE assessment for the RV beltline materials is bounded (limited) by the USE value for the intermediate shell plate C-7-2. The staff calculated the projected USE value to be 57 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 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 shell plate C-7-3 and lower shell plate C-8-1 are predicted to have the most limiting USE values of 57.4 and 57.6 ft-lb, respectively, 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 1 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 lower shell axial welds 3-203 A, B, and C are the most limiting materials and calculated the end-of-extended-operating-term RT_{PTS} value for these materials to be 240°F. All of these materials meet 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 lower shell axial welds 3-203A, B and C are predicted to have the most limiting RT_{PTS} value of 234°F. 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 50, Appendix G, are designed to protect the integrity of the reactor coolant pressure boundary in nuclear power plants. Appendix G to 10 CFR 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 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 18.2.12.1).

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 35 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), and RCPs, are designed in accordance with the requirements of the ASME Code, Section III. The reactor coolant piping was designed in accordance with the requirements of ANSI B31.7, Nuclear Power Piping. 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% 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 18.2.7.

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 calculations 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 current piping analyses remain valid for the period of extended operation.

Design cycles are identified in Table 9.3-9 of the UFSAR for the regenerative and letdown heat exchangers. Although these are Class 2 components and are not specifically required to be analyzed for fatigue under ASME Section III Code rules, the NSSS supplier specified that the heat exchangers be capable of operating under these UFSAR transients. The projected cycles for 60 years are bounded by the Class 1 component design cycles discussed in the ASME Section III, Class 1 components discussion above. These reviews concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation. Therefore, the analyses remain valid for the period of extended operation.

Therefore, the ASME Section III, Class 2 and 3 and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). 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 7000 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 (22,000). 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, and
- 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 Program (ISI) 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, and
- 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, in the event FPL selects the last option, the inspection details, including scope, qualification, method, and frequency, will be provided to the

NRC for review prior to the period of extended operation. 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, the following areas previously classified as a mild environment are now classified as harsh environment due to radiation:

- 1A CS pump and 1A HPSI pump room, and
- HVAC Equipment Area – reactor auxiliary building 43' elevation.

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 18.2.6 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 7000 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. UFSAR Appendix 3G qualifies the bellows for 7000 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 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 Unit 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 SGs 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 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 FMP, (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) loads + safe shutdown earthquake (SSE) loads 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 1 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 crane,
- Intake structure bridge crane, and
- Reactor containment building auxiliary telescoping jib crane.

(Note: The fuel handling equipment does not require a TLAA evaluation because their lifting function is not in the scope of license renewal)

The cranes identified above are designed in accordance with Specification 61 of the Electrical Overhead Crane Institute (EOCI-61), Florida State Regulations and South Florida Building Code, and American Institute of Steel Construction (AISC) Specification, (AISC 6TH Ed.). Although not originally in accordance with Crane Manufacturers Association of America, CMAA-70, the original design of the cranes meets the CMAA-70 requirements. An evaluation of the cranes to the requirements of NUREG-0612, Control of Heavy Loads, concluded the cranes meet or exceed CMAA-70 criteria. Cranes designed in accordance with CMAA-70 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 St. Lucie Unit 2 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 handing 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 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, Light Load Handling System (Related to Refueling) the SSCs associated with the LLHS related to refueling are not modified for EPU purposes, and will continue to use the current Areva-NP design 14x14 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 as 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.

Unit 1 Core Support Barrel

During the 1983 refueling outage, the core support barrel (CSB) and thermal shield were observed to be damaged. The thermal shield was permanently removed. Four lugs were found to have separated from the CSB, and through-wall cracks were found adjacent to the lug areas. The CSB was repaired at the thermal shield support lug locations. As part of the LRA, FPL determined that two specific elements of the CSB repair qualify as TLAAs: (1) the fatigue analysis of the CSB middle cylinder considered only 80% of the original design cycles and (2) the acceptance criteria for the CSB expandable plugs' preload based on irradiation induced stress relaxation was based on 32 EFPY. The following documents the acceptability of the subject TLAAs with respect to EPU.

Fatigue Analysis of CSB Middle Cylinder

The CSB middle cylinder fatigue analysis was revised, and satisfies ASME Section III Class 1 code criteria for the original design cycles. The 40-year design cycles bounds the extended period of operation. The CSB fatigue analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Analyses have been performed to assess the structural integrity of the CSB under design loading conditions that reflect EPU. These analyses take into account the structural conditions of the CSB for the period of extended operation. The results of these analyses demonstrate that the TLAA associated with the CSB remains acceptable for the EPU. Therefore EPU has no impact upon the structural integrity of the CSB.

CSB Expandable Plugs

The original CSB plug preload analysis was revised for increased fluence (54 EFPY) and irradiation-induced relaxation input. The analysis concluded that all the repair plug flange deflection measurement readings are sufficient to meet the minimum required values and maintain the plugs' preload. The CSB repair plugs will therefore perform their intended function for the period of extended plant operation. The CSB preload stress relaxation analysis 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).

Analyses have been performed to calculate the minimum plug-flange deflection requirements of the CSB repair plugs using revised fluence and irradiation-induced relaxation input reflecting the EPU over the increased plant lifetime of 54 EFPY. As-measured deflections are evaluated against the revised minimum requirements.

The actual plug-flange deflection measurement tool readings exceed the minimum required values in all cases. Therefore, the deflection related acceptance criterion is met, and the CSB repair plugs will perform their intended function under EPU conditions through 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. 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. This issue is not applicable to the St. Lucie Unit 1 replacement pressurizer since it does not have Alloy 600 nozzles.

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. 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.

An analysis (Reference 1) of the small bore nozzles was completed using plant-specific data. This 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 (based on plant operating history it has been projected that over the 60-year life of the plant it will experience less than 50% of the transient cycles assumed in the analysis). The minimum margin in the stress intensity associated with the end of life (60-year) crack for the hot leg nozzles is 20%. 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).

There are two mechanisms that can result in growth of the existing cracks – 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. At power, the dissolved hydrogen concentrations maintained in the RCS reacts to maintain DO below detection limits.

While EPU will result in a small increase in RCS temperature (T_{hot} changes from 594°F to 604°F, which is approximately 1.35%), 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 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 EPU conditions, 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 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% of the time, at intermediate temperature startup conditions for 2% of the time, and at shutdown conditions for 10% 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 DO 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 DO content. Thus, any operation with capacity factors greater than 88% (time at shutdown of less than 10%) 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 89.2 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 1. 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. CN-CI-02-69, Rev. 0, Evaluation of Fatigue Crack Growth Associated with Small Diameter Nozzles for St. Lucie 1 & 2, October 2002.