May 16, 2006

Mr. J. A. Stall
Senior Vice President, Nuclear and
Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE PLANT, UNIT NO. 2 - ISSUANCE OF AMENDMENT FOR REDUCTION IN REACTOR COOLANT SYSTEM FLOW AND INCREASE IN STEAM GENERATOR TUBE PLUGGING LIMIT (TAC NO. MC8757)

Dear Mr. Stall:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 145 to Renewed Facility Operating License No. NPF-16 for the St. Lucie Nuclear Plant, Unit No. 2, in response to your application dated October 21, 2005, as supplemented by letters dated February 28, March 28 and April 24, 2006.

This amendment permits operation with a reduced reactor coolant system flow rate and a reduction in reactor thermal power that will support a maximum steam generator tube plugging level of 42 percent per steam generator.

This amendment consists of changes to the Technical Specifications (TSs) and the following addition to license condition 3.A, “Maximum Power Level”:

> Commencing with the startup for Cycle 16 and until the Combustion Engineering Model 3410 Steam Generators are replaced, the maximum reactor core power shall not exceed 89 percent of 2700 megawatts (thermal) if:
>
> a. The Reactor Coolant System Flow Rate is less than 335,000 gpm but greater than or equal to 300,000 gpm, or
>
> b. The Reactor Coolant System Flow Rate is greater than or equal to 300,000 gpm AND the percentage of steam generator tubes plugged is greater than 30 percent (2520 tubes/SG) but less than or equal to 42 percent (3532 tubes/SG).
>
> This restriction in maximum reactor core power is based on analyses provided by FPL in submittals dated October 21, 2005 and February 28, 2006, and approved by the NRC in Amendment No. 145, which limits the percent of steam generator tubes plugged to a maximum of 42 percent (3532 tubes/SG) in either steam generator and limits the plugging asymmetry between steam generators to a maximum of 600 tubes.

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

Sincerely,

/RA/

Brendan T. Moroney, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-389

Enclosures:
1. Amendment No. 145 to NPF-16
2. Safety Evaluation

cc w/enclosures: See next page

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Sincerely,

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FLORIDA POWER & LIGHT COMPANY

ORLANDO UTILITIES COMMISSION OF

THE CITY OF ORLANDO, FLORIDA

AND

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. 50-389

ST. LUCIE PLANT UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 145
Renewed License No. NPF-16

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

   A. The application for amendment by Florida Power & Light Company, et al. (the licensee), dated October 21, 2005, as supplemented February 28, March 28 and April 24, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Renewed Facility Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Facility Operating License No. DPF-16 is hereby amended to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 145, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

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

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Michael L. Marshall, Jr., Chief
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Operating License
and Technical Specifications

Date of Issuance: May 16, 2006

ATTACHMENT TO LICENSE AMENDMENT NO. 145

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-16

DOCKET NO. 50-389

Replace page 3 of Renewed Operating License No. NPF-16 with the attached pages 3 and 3a.

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

Remove Pages	Insert Pages
3/4 2-14	3/4 2/14
3/4 2-15	3/4 2-15
3/4 4-15	3/4 4-15

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 145

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-16

FLORIDA POWER AND LIGHT COMPANY, ET AL.

ST. LUCIE PLANT, UNIT NO. 2

DOCKET NO. 50-389

1.0 INTRODUCTION

By letter to the U.S. Nuclear Regulatory Commission (NRC, the Commission) dated October 21, 2005, as supplemented by letters dated February 28, March 28 and April 24, 2006, Florida Power and Light Company, et al. (FPL, the licensee), requested to amend Renewed Operating License NPF-16 for St. Lucie Unit 2.

At the time of the initial submittal, St. Lucie Unit 2 was operating in Cycle 15 with an average steam generator (SG) tube plugging (SGTP) level of about 19 percent in its Combustion Engineering (CE) Model 3410 SGs. In Amendment No. 138 (Reference 6) the NRC staff approved a Technical Specifications (TS) minimum reactor coolant system (RCS) flow requirement of 335,000 gallons per minute (gpm) based on an analysis that assumed a maximum level of 30-percent SGTP. Based on the projections for SG tube inspections during the Cycle 16 refueling outage, the licensee concluded that a combination of tube plugging and tube sleeving activities would be needed to maintain an effective SGTP level below the currently approved level of 30 percent and meet the TS minimum RCS flow requirement of 335,000 gpm. The licensee indicated that an unexpected situation during the sleeving activities might result in excessive SGTP levels that would challenge the 30-percent SGTP limit and TS RCS flow limit. The proposed amendment is necessary to address unexpected increases in the SGTP level from 30 percent to 42 percent in each of the two current SGs.

The proposed amendment changes TSs to permit a reduction in the minimum RCS flow rate from 335,000 gpm to 300,000 gpm subject to new license conditions. The license conditions limit the maximum reactor thermal power to 89 percent of rated thermal power (RTP) of 2700 megawatts thermal (MWt) while operating at the reduced RCS flow rate or with an increased SGTP level between 30 percent and 42 percent per SG with a maximum tube plugging asymmetry of 7 percent (600 tubes) between SGs.

The licensee's supplementary submittals dated February 28, March 28 and April 24, 2006, provided clarifying information that did not change the scope of the proposed amendment as described in the original notice of proposed action published in the *Federal Register* and did not change the initial proposed no significant hazards determination.

2.0 REGULATORY EVALUATION

2.1 Accident Analyses

Section 3.0 of this safety evaluation addresses changes in the accident analyses. In the current licensing basis for St. Lucie Unit 2, the licensee is required to perform analyses of applicable loss-of-coolant accidents (LOCAs) and non-LOCAs using NRC-approved methods to support proposed amendments and associated TS changes. The results of analyses must demonstrate compliance with the following regulatory requirements:

General Design Criterion (GDC)10, “Reactor Design,” in Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, “Domestic Licensing of Production and Utilization Facilities,” 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 the effects of anticipated operational occurrences (AOOs).

GDC 15, “Reactor Coolant System Design,” 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 27, “Combined Reactivity Control Systems Capability,” requires that the reactivity control system be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system (ECCS), 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.

GDC 35, “Emergency Core Cooling,” requires that the ECCS safety function be designed 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.

10 CFR 50.46 requires that the ECCS performance meet the acceptance criteria in terms of the limits of the peak cladding temperature, maximum cladding oxidation and maximum hydrogen generation, as the adequate capabilities for the core geometry cooling and RCS long-term cooling during postulated LOCAs.

The guidance for implementing the requirements of GDCs 10, 15, 27, 35, and 10 CFR 50.46 related to the design-basis event analyses and the acceptance criteria is provided in the NRC’s Standard Review Plan (SRP), NUREG-0800. To be consistent with the current licensing basis, the NRC staff’s review of the safety analyses for the proposed amendment is based on the guidance specified in applicable sections of the SRP.

2.2 Dose Consequences

Section 4.0 of this safety evaluation addresses the impact of the proposed changes on previously analyzed design basis accident radiological consequences and the acceptability of the revised analysis results. The evaluation is based on the accident dose guidelines in 10 CFR 100.11, as supplemented by accident-specific criteria in Section 15 of the SRP for accidents other than the SG tube rupture, and the accident dose criteria in 10 CFR 50.67, as supplemented in Regulatory Position 4.4 of Regulatory Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” for the SG tube rupture accident only, and 10 CFR Part 50 Appendix A, GDC 19, “Control Room,” as supplemented by Section 6.4 of the SRP. Except where the licensee proposed a suitable alternative, the staff utilized the regulatory guidance provided in the following documents in performing this review.

1. RG 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”

2. SRP Section 15.0.1, “Radiological Consequence Analysis Using Alternative Source Terms”

The NRC staff also considered relevant information in the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR) and TSs. St. Lucie Unit 2 has a previous selective implementation of an alternative source term (AST), in accordance with 10 CFR 50.67, for only the SG tube rupture accident. This partial implementation was approved in Amendment No. 138 for 30-percent SGTP at St. Lucie Unit 2.

3.0 TECHNICAL EVALUATION

The purpose of the NRC staff’s review is to confirm that the licensee performed safety analyses with acceptable methods, to verify that the analytical results meet the required acceptance criteria, and to assure that the proposed TSs and license conditions appropriately reflect the results of the acceptable safety analyses. The following evaluation is based on the NRC staff’s review of the proposed amendment and its associated TS changes with supporting analyses documented in References 1, 2 and 3. The technical justification for the proposed amendment is based primarily on Westinghouse Commercial Atomic Power report WCAP-16489-NP, “St. Lucie Unit 2 42-Percent Steam Generator Tube Plugging Licensing Report,” dated October 2005 (Ref. 4). This evaluation addressed the following areas: (1) fuel design; (2) nuclear design; (3) analytical methods; (4) non-LOCA transients analyses; (5) LOCA analyses; and (6) the proposed TS changes.

3.1 Fuel Design

This section documents the NRC staff’s evaluation of the licensee’s analysis pertaining to the fuel design aspects of Reference 4.

The fuel system mechanical design of St. Lucie Unit 2 consists of 16x16 CE HID-1L fuel with Zircaloy-4/OPTIN cladding. This is the fuel design that will be used for Cycle 16. There are no changes to the fuel assembly design for Cycle 16 other than the use of Inconel top grids. There are no changes to the fuel assembly structural characteristics created by the use of an Inconel top grid, thus the NRC staff determined that the fuel assembly is acceptable.

The fuel system consists of fuel rods, spacer grids, guide thimbles, top and bottom end plates, and reactivity control rods including burnable poison rods. The NRC staff’s review uses the following criteria to evaluate the fuel system design: (1) the fuel system is not damaged as a result of normal operation and AOOs; (2) fuel system damage is never so severe as to prevent control rod insertion when it is required; (3) the number of fuel rod failures is not underestimated for postulated accidents; and (4) coolability is always maintained. The NRC staff's review covers fuel system damage mechanisms, failure mechanisms, and safety of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on (1) 10 CFR 50.46 for core cooling, (2) GDC 10 for assuring that SAFDLs are not exceeded during any condition of normal operation, including AOOs, (3) GDC 27 for the reactivity control system being designed with appropriate margin, and in conjunction with the ECCS, being capable of controlling reactivity and cooling the core under postaccident conditions, and (4) GDC 35 for providing an ECCS to transfer heat from the reactor core following any loss of reactor coolant. Specific review criteria are contained in SRP Section 4.2.

The proposed increase in the SGTP limit would cause a small decrease in core average temperature due to the combined effects of reduced core power and flow on the core nonheat-flux structures. The licensee evaluated effects and they were found to be negligible. Another effect of the reduction in RCS flow is the potential for flow-induced vibration. The reactor internals were evaluated by the licensee for the reduced RCS flow rate and found to be acceptable.

Flow tests were performed as a part of the 16x16 CE HID-1L assembly development. Acceptable results were found for the 16x16 CE HID-1L assembly for a spectrum of flow rates that encompasses the anticipated (300,000 gpm) flow rate.

Although not currently planned for use in Cycle 16, the potential to use ZIRLO cladding was evaluated in Reference 4. The licensee may use ZIRLO cladding in future cores and its use was, therefore, evaluated by the NRC staff.

The licensee performed fuel rod design evaluations for the 16x16 CE HID-1L fuel using NRC-approved models and design criteria methods (Refs. 8 through 15). A specific assumption used in the verification of the fuel rod design criteria for the St. Lucie Unit 2 fuel is that there is 42-percent SGTP at 89 percent power and the associated reduced RCS flow rate is 300,000 gpm.

The evaluations of fuel rod design are discussed below. References in the discussion to Condition I through Condition IV refer to the following American Nuclear Society (ANS) classification of plant events in accordance with anticipated frequency of occurrence and potential radiological consequences to the public:

Condition I	Normal operation and operational transients
Condition II	Faults of moderate frequency
Condition III	Infrequent faults
Condition IV	Limiting faults

Internal Gas Pressure

Rod internal pressure is considered a driving force for fuel system damage that could contribute to the loss of dimensional stability and cladding integrity. The criterion used to determine acceptability is that the fuel rod internal hot gas pressure shall not exceed the critical maximum pressure that has been determined to cause an outward cladding creep rate that is in excess of the fuel radial growth rate anywhere locally along the entire active fuel length of the fuel rod. The NRC staff confirmed that the licensee's evaluation determined that the critical pressure limit will not be violated at any time in life for the anticipated operation of St. Lucie Unit 2.

Departure from Nucleate Boiling (DNB) Propagation

The criterion used to determine acceptability is that the radiological dose consequences of DNB failures shall remain within the specified limits. The calculation of DNB propagation depends on the rod internal gas pressure, the amount of high-temperature creep, and the high-temperature rupture stress.

The NRC staff confirmed that the licensee's evaluation determined that no DNB propagation occurs with the maximum rod internal pressures predicted for St. Lucie Unit 2.

Fuel Rod Stress and Strain

The criterion used to determine acceptability is that the stress and strain limits in the fuel design shall not be exceeded for either normal operations or AOOs.

The NRC staff confirmed that the licensee's evaluation of the fuel rod stress and strain for St. Lucie Unit 2 considering differential cladding pressures, creep, cladding growth and oxide buildup satisfied the stress and strain limits.

Maximum Fuel Temperature

The criterion used to determine acceptability is that the fuel rod centerline temperature shall not exceed the fuel melt temperature, after accounting for fuel degradation due to burnup and the addition of burnable absorbers.

The NRC staff confirmed that the licensee's evaluation for St. Lucie Unit 2 determined that the fuel melt temperature limit will not be exceeded at any time in life for anticipated operation of St. Lucie Unit 2.

Fuel Rod Fatigue Damage

The criterion used to determine acceptability is that for the number and types of transients that will occur during ANS Condition I reactor operation, the end-of-life (EOL) cumulative fatigue damage factor in the cladding and in the end-cap welds must remain less than 0.8.

The NRC staff confirmed that the licensee's evaluation of the fatigue damage for St. Lucie Unit 2 considering rod temperature and pressure, cladding creep, thermal expansion, and pellet swelling, and determined that the fatigue damage factor criterion is met.

Cladding Creep

The criterion used to determine acceptability is that the time that is required for radial buckling of the cladding must exceed the reactor operating time necessary for the appropriate batch to accumulate its design average discharge burnup. Further, this criterion must be satisfied for continuous reactor operation at any reasonable power level and during any ANS Condition I, II, or III situation. The acceptability criterion will be considered satisfied if it can be demonstrated that axial gaps longer than 0.125 inch will not occur between fuel pellets and that the plenum spring radial support capacity will remain sufficient to prevent cladding collapse under all design conditions.

The NRC staff confirmed that the licensee conducted an evaluation considering differential cladding pressures, creep, cladding growth, and oxide buildup, and determined that the cladding collapse criterion is met for the St. Lucie Unit 2 fuel-design cladding.

Shoulder Gap

The criterion used to determine acceptability is that the axial length between end fittings must be sufficient to accommodate any differential thermal expansion and any irradiation-induced differential growth between the fuel rods and the guide tubes in such a manner that it can be shown with 95-percent confidence that no such interference exists. This design criterion is commonly referred to as shoulder gap and it is evaluated using the irradiation-induced and thermal growth characteristics of the fuel rod cladding.

The NRC staff confirmed that the licensee’s evaluation for St. Lucie Unit 2 determined that the shoulder gap criterion is met for the St. Lucie Unit 2 fuel design cladding.

Seismic and LOCA Impact

Earthquakes and postulated pipe breaks in the RCS would result in external forces on fuel assemblies. The fuel rod cladding must be capable of withstanding the loads that result from the mechanical excitations that occur during a seismic and/or a LOCA without failure that may result from excessive primary stresses.

The licensee evaluated the seismic and LOCA impact for St. Lucie Unit 2 and indicated that, although there may be minor changes to the allowable stress margins that occur as a result of a change in cladding material (from OPTIN to ZIRLO), there will be no impact since there are significant stress margins that exist for the cladding under the postulated loading conditions. In addition, the licensee evaluated the 16x16 CE HID-1L fuel design with Zircaloy-4/OPTIN or ZIRLO cladding and an Inconel top grid, and confirmed that there will be no impact on the seismic/LOCA evaluation. Further, the licensee confirmed that the reduced RCS flow rate, and the resulting window for T_{cold} and T_{hot}, will have no impact on the evaluation.

Based on the licensee’s evaluation discussed in Section 3.1 above and Section 3.4 below, the NRC staff found that the licensee performed evaluations of the fuel mechanical design using methods previously approved by the NRC and the results confirmed compliance with the acceptable fuel design criteria. The NRC staff determined that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Therefore, the NRC staff concluded that the fuel system mechanical design is acceptable for a SGTP level up to 42 percent at St. Lucie Unit 2 with a maximum power of 89 percent of RTP and a minimum RCS flow of 300,000 gpm.

3.2 Nuclear Design

This section documents the NRC staff's evaluation of the licensee's analysis pertaining to the non-LOCA nuclear design aspects of Reference 4.

The review of the nuclear design includes the fuel assemblies, control systems, and reactor core. The review was conducted to confirm that fuel design limits will not be exceeded during normal operation or AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core.

Significant levels of tube plugging have the potential to affect the core power distribution and reactivity due to perturbations imposed on the reactor coolant pump (RCP) flow rate and coolant temperature.

The effects of the following proposed changes to the operation of the St. Lucie Unit 2 were evaluated.

1. An increase in the amount of SGTP from 30 percent to 42 percent. This increase in SGTP was analyzed as having produced a reduced RCS flow rate of 300,000 gpm.

2. A power level restriction to 89 percent of RTP.

The specific values of the core safety parameters (e.g., power distributions, peaking factors, rod worths, and reactivity parameters) are primarily loading-pattern dependent. The variations in the loading-pattern dependent safety parameters were expected to be typical of the normal cycle-to-cycle variations for the standard fuel reloads.

Approved nuclear design analytical models and methods (Refs. 16 through 18) that describe the neutronic behavior of the 16x16 CE HID-1L fuel design with either Zircaloy/OPTIN or ZIRLO cladding were used.

The fuel burnup design will remain at 60,000 MW-days per metric ton of uranium.

Using the NRC-approved methods documented in WCAP-9272 (Ref. 5), the licensee evaluated the effect of the proposed changes on the reload core analysis to assure that the values for the key safety parameters would remain applicable for the expected operating condition. This allowed the majority of any safety analysis reevaluations or reanalyses to be completed prior to the cycle-specific design analysis. No changes to the nuclear design philosophy, methods or models were made.

The reload design philosophy employed by the licensee includes the evaluation of the reload core key safety parameters that comprise the nuclear design dependent input to the UFSAR for each reload cycle. These key safety parameters are evaluated by the licensee for each St. Lucie Unit 2 reload cycle. If one or more of the parameters should fall outside the bounds that are assumed in the reference, baseline safety analysis, then the affected transients must be reevaluated or reanalyzed using standard methods and the results must be documented in the Reload Safety Evaluation for that particular cycle.

Changes to the core power distribution and peaking factors are the result of normal cycle-to-cycle variations in core loading patterns. Feed enrichment variation and the insertion of fresh burnable absorbers can and must be employed to control the peaking factors. However, compliance with the peaking factor TS will be assured by employing these methods.

The following two items would require plant TS changes because they impact the nuclear design:

1. The maximum allowed core thermal power limit was reduced to 89 percent of RTP.

2. The RCS minimum TS flow rate was reduced.

The following four items needed changes to the core operating limits report (COLR) since they reflect cycle-specific values of nuclear parameters:

1. The COLR limit for peak linear heat rate (PLHR) (limited by the large-break LOCA) was reduced.

2. The COLR limit for the linear heat rate limiting condition for operation when operating on the excore detector monitoring system was reduced.

3. The COLR limit for the total integrated radial peaking factor was modified, and

4. The COLR limits for the DNB parameter, fraction of maximum allowable power level versus axial shape index were reduced.

The changes to the COLR limits in combination with the restriction of operation to 89 percent power compensates for the reduced RCS flow while providing additional peaking margin to accommodate the higher peaking that is associated with the use of a reload core design optimized for 30-percent SGTP with 42-percent SGTP.

The NRC staff has reviewed the licensee's evaluation of the impact of having 42-percent SGTP on core physics, and found that the licensee performed the analyses using NRC-approved methods and the results of the analyses confirmed that the impact of having 42-percent SGTP is insignificant. Therefore, the NRC staff agreed with the licensee that the acceptance criteria for the nuclear design continue to be satisfied. Further, any future St. Lucie Unit 2 core reload designs and analyses will continue to be performed using NRC-approved methods, thus assuring that all acceptance criteria will continue to be satisfied. Therefore, the NRC staff concluded that the nuclear design is acceptable for the St. Lucie Unit 2 licensing application.

3.3 Methodologies for Non-LOCA Analyses

The licensee used the following methodologies for non-LOCA analyses:

3.3.1 Westinghouse Reload Evaluation Methodology

The Westinghouse reload evaluation methodology is documented in WCAP-9272-P-A (Ref. 5). This method is based on the concept of a bounding analysis. The method assumes that the validity of the reference analysis is established for the reload core under consideration on the basis that the key safety parameters for the reload core use values that are conservatively bounded by those in the reference analysis. For each reload core, the values of the key safety parameters are examined to determine whether a transient analysis is required or not. If all key safety parameters are conservatively bounded, the reference safety analysis remains valid for the reload core. If a reload parameter is not bounded, further analysis or evaluation is required for the reload core. Since WCAP-9272-P-A was previously approved (Ref. 6) for St. Lucie Unit 2 licensing applications and the licensee used the NRC-approved Westinghouse methods and codes (discussed in Sections 3.3.2 through 3.3.4 below) to perform its reload analysis, the restriction of the NRC staff's safety evaluation approving the methodology was satisfied. Therefore, the NRC staff concluded that the methodology documented in WCAP-9272-P-A continues to be acceptable.

3.3.2 Revised Thermal Design Procedure for Thermal-Hydraulic Analyses

The licensee used the revised thermal design procedure (RTDP) to perform statistical core thermal-hydraulic analyses. Unlike the deterministic method, in which the uncertainties of various plant and operating parameters are assumed simultaneously at their worst uncertainty limits in the safety analyses, the RTDP methodology statistically accounts for the system uncertainties in plant operating parameters, fabrication parameters, nuclear and thermal parameters, as well as the DNB correlation uncertainty. The RTDP methodology establishes an RTDP DNB Ratio (DNBR) limit that statistically accounts for the effects on DNB of the key parameters. Therefore, when the RTDP methodology is used to perform thermal-hydraulic analyses, initial-condition uncertainties are not included in the plant parameters that are sensitive to the DNBR calculations, as they are already included in the RTDP DNBR limit. The RTDP methodology is documented in WCAP-11397-P-A (Ref. 19).

The design DNBR limit must be calculated based on the system uncertainties in plant operating parameters and the uncertainties of the DNB correlation and computer codes used for the specific plant. In Reference 4, the licensee indicated that the RTDP in WCAP-11394-P-A and St. Lucie Unit 2 plant specific uncertainties were used to determine the design DNBR limit. Specifically, the values of uncertainties were chosen (in Table 4-2 of Reference 4) to be consistent with those used in the current analysis for the following St. Lucie Unit 2 plant parameters: (1) the enthalpy rise factor, (2) the power peak factor, (3) uncertainties in inlet flow distribution, and (4) uncertainties based on surveillance data associated with RCS flow, coolant temperature, pressure and reactor core power. The NRC staff found that the RTDP methodology was previously approved (Ref. 6) for St. Lucie Unit 2 in performing statistical core thermal-hydraulic analyses and the licensee's calculation of the design DNBR limit adequately followed the approved RDTP method described in WCAP-11397-P-A. Therefore, the NRC staff concluded that the use of the RDTP as documented in WCAP-11397-P-A to perform statistical core thermal-hydraulic analyses for St. Lucie Unit 2 continues to be acceptable.

3.3.3 Method for the Rod Ejection Analysis

As documented in WCAP-7588, Revision 1-A (Ref. 20), the NRC has generically approved a method to perform the rod ejection analysis for Westinghouse plants that relies on spatial kinetics models. As indicated in Reference 6, this methodology was approved by the NRC for the St. Lucie Unit 2 analysis of the rod ejection event. Therefore, the licensee's application of this methodology to St. Lucie Unit 2 continues to be acceptable.

3.3.4 Computer Codes Used for Non-LOCA Transient Analyses

The licensee performed non-LOCA analyses with the following computer codes:

3.3.4.1 VIPRE with the ABB-NV and W-3 Critical Heat Flux Correlations

The VIPRE code was used in thermal-hydraulic analyses to determine coolant density, mass velocity, enthalpy, vapor void, static pressure, and the DNBR distribution along parallel flow channels within the reactor core under normal operational and transient conditions. When applying the VIPRE code, the licensee used the ABB-NV and W-3 Critical Heat Flux correlations to calculate DNBRs.

The safety DNBR limits have been imposed to assure that there is at least a 95 percent probability at a 95 percent confidence level (95/95) that the hot rods in the core do not experience a DNB during a transient. For CE 16x16 fuel assemblies in the St. Lucie Unit 2 reactor core, the licensee used the VIPRE code and the ABB-NV correlation with a correlation limit of 1.13 for the DNBR analysis. The ABB-NV correlation limit of 1.13 and the RTDP methodology were applied with St. Lucie Unit 2 plant-specific data using the values of the thermal hydraulic parameters listed in Table 4-1 of Reference 4 and uncertainty factors listed in Table 4-2 of Reference 4 at a 95/95 confidence/probability level to define design DNBR limits. In DNBR analyses, the design DNBR limits are increased to provide DNB margin to offset the effect of rod bow and any other DNBR penalties that may occur, to provide flexibility in design and operation of the plant. The increased DNBR is referred to as the safety analysis limit (SAL) DNBRs as shown in Table 4-4 of Reference 4. The NRC staff found that (1) the use of the VIPRE code and the ABB-NV correlation with the associated 95/95 DNBR limit of 1.13 for CE 16x16 fuel assemblies was approved previously for use in the St. Lucie Unit 2 core thermal-hydraulic analysis (Ref. 6), and (2) the calculations of the design limit DNBRs adequately used the acceptable RTDP methodology with the DNBR-parameter related uncertainties specific to the St. Lucie Unit 2 plant. Therefore, the NRC staff concluded that the VIPRE code with the ABB-NV and the associated SAL DNBRs listed in Table 4-4 of Reference 5 continues to be acceptable for the DNBR analyses for St. Lucie Unit 2.

As indicated in Section 4.2 of Reference 4, the W-3 DNB correlation and standard thermal design procedure (STDP) were used at design conditions at which the ABB-NV correlation and RTDP were not applicable. The STDP is the traditional design method with parameters uncertainties applied deterministically in the limiting direction. The W-3 correlation with its associated SAL DNBR was previously approved by the NRC for St. Lucie Unit 2 licensing application (Ref. 6) and, thus, it continues to be acceptable for DNBR analyses.

3.3.4.2 RETRAN

RETRAN simulates a multi-loop system using a model containing a reactor vessel, hot-leg and cold-leg piping, SGs, and pressurizer. The code also includes point kinetics and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the SG uses a detailed nodalization for thermal transients. As documented in Reference 26, the code was previously approved by the NRC for Westinghouse to analyze system responses to non-LOCA transients for Westinghouse pressurized-water reactors (PWRs).

In support of the St. Lucie Unit 2 30-percent SGTP licensing application, the licensee modified RETRAN to include the following CE-designed plant logic and signal processing models for safety analyses: (1) power calculation; (2) thermal margin/low pressure reactor trip, (3) variable high power reactor trip; (4) pressurizer reactor trip functions; (5) RCS flow related reactor trip function; (6) SG level trip functions; (7) turbine trip/manual reactor trips; (8) rate of change of power reactor trip function; (9) asymmetric SG steam pressure reactor trip function; (10) high local power density reactor trip; and (11) low SG pressure reactor trip.

The NRC previously reviewed and approved (Ref. 6) the licensee's use of the modified RETRAN computer code in performing analyses of the following events for St. Lucie Unit 2: (1) increase in feedwater flow rate; (2) decrease in feedwater temperature; (3) pre-trip and post-trip steam line break (SLB) events; (4) loss of condenser vacuum/turbine trip; (5) asymmetric SG transient (ASGT); (6) feedwater line break; (7) complete loss of forced flow; (8) RCP seized rotor/shaft break; (9) uncontrolled rod cluster control assembly withdrawal at power; (10) control element assembly (CEA) drop event; (11) chemical and volume control system (CVCS) malfunction resulting in an increase in RCS inventory; and (12) inadvertent opening of the pressurizer relief valve. Therefore, the NRC staff concluded that the licensee's use of the modified RETRAN computer code in performing non-LOCA analysis for applicable events continues to be acceptable in support of the St. Lucie Unit 2 42-percent SGTP application.

3.3.4.3 CESEC

This code calculates system parameters such as core power, flow, pressure, temperature, RCS inventory, and valve actions during a transient. CESEC was used to analyze the SG tube rupture and primary line break outside containment events. This approach is the same as that used in the analysis of record (AOR, Ref. 21) and, therefore, continues to be acceptable.

3.3.4.4 TWINKLE and FACTRAN

TWINKLE is a multi-dimensional spatial neutronics code that uses an implicit finite-difference method to solve the two-group transient neutronics equations in one, two, and three dimensions. This code is documented in Reference 27.

FACTRAN is a radial pellet/clad temperature calculation model used to calculate the transient heat flux at the surface of a rod. This code is documented in Reference 28.

The licensee applied TWINKLE and FACTRAN to St. Lucie Unit 2 for analyses of the uncontrolled CEA withdrawal from a subcritical condition event and the CEA-ejection event. Both codes were previously approved (Ref. 6) by NRC for St. Lucie Unit 2 in calculating the neutron kinetics response of a reactor, and hot spot heat flux, respectively, for the proposed events. Therefore, the application of the codes for the proposed use remains acceptable.

3.3.4.5 PHOENIX-P and ANC

Both codes address three-dimensional features of the nuclear characteristics of the fuel. PHOENIX-P is used to generate the cycle-specific nuclear cross sections. ANC with the input from PHOENIX-P is used to calculate nuclear characteristics, such as power distributions, control rod worth, and reactivity feedback coefficients. As indicated in Reference 6, both PHOENIX-P and ANC (Refs. 16 & 17) were previously approved by NRC for the currently approved AOR (Ref. 21). Therefore, the licensee's application of the codes continues to be acceptable.

3.4 Transients and Accidents Analyses

3.4.1 General Approach

The licensee evaluated the cases for each event category discussed in Chapter 15 of the UFSAR, analyzed the limiting cases and presented the results of the analyses in Reference 4. These analyses were performed with the following conditions (Refs. 1 and 4):

1. Maximum power of 89 percent level, decreased from the current 100 percent of RTP of 2700 MWt.

2. Maximum SGTP of 42 percent (3532 tubes/SG), increased from the current 30 percent level (2520 tubes/SG) in each of the two SGs.

3. Maximum tube plugging asymmetry of 7 percent (600 tubes) between the two SGs.

4. Normal operation PLHR of 12.0 kilowatts per foot (kw/ft), decreased from the current PLHR of 12.5 kw/ft.

5. A reduction in the TSs-required minimum RCS flow from 335,000 gpm to 300,000 gpm.

6. Radial peaking factor of 1.72, increased from 1.70, and fuel burnup limited to 60 gigawatt-days per metric ton of Uranium (GWD/MTU).

For DNBR calculations, the allowances on power, temperature, and pressure were determined on a statistical basis and included in the design limit DNBR in accordance with the RTDP. For events that are not DNB limited, or in which the RTDP was not used, the values of the core power, average RCS temperature, and pressurizer and SG pressures were obtained by applying the maximum steady-state measurement errors. The pressurizer safety valves and main steam safety valves (MSSVs) were modeled with inclusion of setpoint allowances. The decay heat model used in the non-LOCA analyses was consistent with the ANS-5.1-1979 residual decay heat model increased by two standard deviations. The trip setpoints of the reactor protection system (RPS) and engineered safety feature actuation system included instrumentation uncertainties and actuation delay times.

Although the licensee will use the 16x16 CE HID-1L fuel with Zircaloy-4/OPTIN cladding in the Cycle 16 core for St. Lucie Unit 2, it performed non-LOCA analyses based on the St. Lucie Unit 2 core containing the 16x16 CE HID-1L fuel with incorporation of the ZIRLO cladding material. The effect on non-LOCA analyses of changing from the Zircaloy-4/OPTIN to ZIRLO cladding depends on difference in thermophysical properties of Zircaloy-4/OPTIN and ZIRLO. In a previous evaluation, the NRC staff determined (Ref. 25) that the use of Zircaloy-4/OPTIN or ZIRLO will have no difference in the analysis because there is no difference in the input parameters. Therefore, the NRC staff concluded that the non-LOCA analysis for the CE fuel with ZIRLO is applicable to the CE fuel with Zircaloy-4/OPTIN to be installed in the Cycle 16 core for St. Lucie Unit 2.

The licensee took credit for the time delay of 3 seconds between the turbine trip and the loss-of-offsite power (LOOP) in the analysis of the locked rotor event. Since the LOOP is delayed for 3 seconds after the turbine trip, the control rods are inserted well into the core before the RCP coastdown (due to a loss of power to the RCPs resulting from a LOOP) begins. The resulting reactor power reduction compensates for the reduced flow encountered once the power to the RCPs is lost. In considering the LOOP effects, the licensee also included in the applicable analyses the effect of the immediate loss of one 6.9 kilovolt (kv) bus and the associated two RCPs due to plant-centered failures following a reactor/turbine/generator trip as a result of a plant-centered component failure, such as failure of a fast bus transfer (FFBT). The assumption of LOOP delay time of 3 seconds after the turbine trip and the inclusion of FFBT as a single failure are consistent with that assumed in the current AOR (Refs. 6 and 21), and therefore, are acceptable.

3.4.2 Non-LOCA Transients Analyses

The NRC staff's review of the non-LOCA analyses is discussed in the following Sections.

3.4.2.1 Increase in Feedwater Flow

Section 5.1.1 of the St. Lucie Unit 2 licensing report (Ref. 4) documents the results of the analysis of an increase in feedwater flow event in support of the proposed license amendment request allowing operation at a maximum power of 89 percent of the RTP and minimum RCS flow of 300,000 gpm with the maximum SGTP level of 42 percent in each SG and maximum tube plugging asymmetry of 7 percent between SGs. The event may be caused by system malfunctions or operator actions that result in an inadvertent opening of a feedwater control valve. The excessive feedwater flow reduces reactor coolant temperature, which, in turn, causes a power increase because of the effects of the negative moderator temperature coefficient of reactivity. The reactor trip from signals of high neutron flux, variable high power, low pressurizer pressure, thermal margin/low pressure, or low SG pressure trip provides protection against undesirable conditions.

The licensee performed the analysis using RETRAN for RCS response calculations and VIPRE for DNBR calculations. The analysis consists of both the 89-percent power and hot zero-power cases. In the DNBR calculations, the initial reactor power, RCS pressure and temperature were assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A. The licensee assumed that the increase in feedwater flow event is caused by opening of the feedwater control valves to maximum capacity, resulting in a maximum step increase to 120 percent of the nominal full-power feedwater flow to both SGs. The feedwater temperatures were assumed to be 420.8 degrees Fahrenheit (°F) and 240 °F corresponding to normal plant conditions for the 89-percent of RTP and zero-power cases, respectively. Maximum reactivity feedback conditions with a minimum Doppler-only power defect was assumed, thereby, maximizing the power increase. The feedwater flow resulting from a fully open control valve is terminated by the SG high-high water level signal or operator action.

The NRC staff confirmed that the licensee performed the analysis using an acceptable method, and that the results of the analysis demonstrated that the consequences of this event meet the acceptance criteria of SRP 15.1.2. Specifically, the calculated minimum DNBR was above the SAL DNBRs. Therefore, the NRC staff concluded that analysis is acceptable.

3.4.2.2 Inadvertent Opening of a SG Safety Valve/Atmospheric Dump Valve

Section 5.1.2 of the St. Lucie Unit 2 licensing report (Ref. 4) documents the analysis of an inadvertent opening of an SG safety valve/atmospheric dump valve (ADV) event. The event, a moderate frequency event, may result in an increase in steam flow. In the presence of a negative moderator temperature coefficient, the excessive cooldown by the increased steam flow increases positive reactivity which, in turn, increases the core power level. As a result of the power increase and RCS pressure decrease, the calculated DNBRs may decrease, possibly causing fuel damage.

Since the steam flow from either the SG safety valve or ADV is within the range of steam flow from various sizes of the SLBs, the consequences of cooldown effects from the inadvertent opening of an SG safety valve or ADV are bounded by that of the SLBs (including both pre-trip with FFBT and post-trip SLBs). As discussed in Sections 5.1.5 and 5.1.6 of Reference 4 and evaluated in Sections 3.4.2.4 and 3.4.2.5 of this report, the analyses of the pre-trip with FFBT and post-trip SLBs show no DNBR below the SAL DNBRs, thus meeting the acceptance criteria of SRP for the moderate-frequency events. Therefore, the NRC staff concluded that the results of the inadvertent opening of an SG safety valve or ADV, a less limiting event than the SLB event, will meet the SRP acceptance criteria for the moderate-frequency events, and are acceptable.

3.4.2.3 Decrease in Feedwater Temperature

Section 5.1.3 of the St. Lucie Unit 2 licensing report (Ref. 4) documents the results of the analysis of a decrease in feedwater temperature event. The event decreases reactor coolant temperature, which, in turn, causes an increase in core power because of the effects of the negative moderator temperature coefficient of reactivity. Since the rate of energy change is reduced as load and feedwater flow decrease, the transient initiated from zero-power conditions is less severe than the at-power case. The licensee's analysis for the limiting case is based on the maximum initial 89-percent power conditions with a decrease in feedwater temperature in both SGs caused by a loss of one string of high-pressure heaters. The loss of a string of feedwater heaters results in a maximum reduced feedwater temperature of 320.8 °F at 89 percent power. The reactor trip signal from the high neutron flux, variable high power, low pressurizer pressure, thermal margin/low pressure, or low SG pressure provides reactor core protection. The high-high SG level trip signal prevents the continuous addition of feedwater at a reduced temperature by tripping the turbine, stopping the main feedwater pumps, and closing the main feedwater pump discharge valves.

The NRC staff confirmed that the licensee performed the analysis using acceptable methods (i.e, RETRAN for RCS response calculations and VIPRE for DNBR calculations). The results of the analysis showed that the calculated minimum DNBR was above the SAL DNBRs, thus meeting the acceptance criteria of SRP Section 15.1.2 with respect to the fuel integrity. Therefore, the NRC staff concluded that the analysis is acceptable.

3.4.2.4 Pre-Trip Main Steam Line Break (MSLB)

Section 5.1.5 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the pre-trip MSLB event. This analysis is supplemented by responses to NRC staff requests for additional information (RAIs) in Reference 2.

The Westinghouse computer codes RETRAN, ANC, and VIPRE were used to simulate the pre-trip MSLB event. These codes have been previously reviewed and approved and their application is consistent with the pre-trip MSLB methodology recently reviewed and approved as part of the 30-percent SGTP license amendment (Ref. 6) as reflected in the latest amendment to Section 15.1.5 of the St. Lucie Unit 2 UFSAR (Ref. 21).

Similarly, the pre-trip MSLB methodology was employed in the selection of initial conditions and assumptions that maximize the power excursion and DNB degradation experienced during the event. Two distinct scenarios were evaluated:

3. Pre-Trip MSLB with FFBT at Reactor/Turbine Trip

4. Pre-Trip MSLB with LOOP

The current UFSAR FFBT case (scenario no. 1 above) includes a 0.25-second delay between turbine trip and reactor trip that delays the 2-RCP coastdown. Responding to the NRC staff's concerns raised in the 30-percent SGTP license amendment (Ref. 6), the revised analysis assumes no delay between reactor trip and turbine trip. Based upon review of the initial conditions and assumptions, the NRC staff concludes that the limiting pre-trip MSLB transient scenarios are acceptable.

Figure 5.1.5-1a of Reference 4 illustrates the break spectrum analysis that identifies the limiting combination of break size and moderator density coefficient with respect to peak core power. Due to moderator density feedback effects, any scenario that includes an RCP coastdown may not be as limiting with respect to peak core power relative to an event that maintains full flow. The pre-trip MSLB with FFBT event was modeled as a composite event with the 2-pump flow coastdown superimposed (in the VIPRE DNB calculation) on the peak power excursion statepoints. This modeling technique is conservative, and the resulting DNB degradation and peak linear heat generation rate bound both the pre-trip MSLB event with full RCS flow and the pre-trip MSLB event with FFBT.

During the review of the 30-percent SGTP license amendment, the NRC staff had concerns regarding the validity of the thermal-hydraulics modeling of inlet flow distribution and crossflow characteristics during a 2-pump coastdown. In response to an RAI, the licensee stated that "Westinghouse is also not aware of any 2-out-of-4 pump coastdown test data that are applicable to a pre-trip steamline break . . . ." Further, the licensee stated that the impact of a

2-pump coastdown on local flow characteristics are offset by conservative assumptions and modeling techniques in the safety analysis methodology. In discussions with the licensee and in response to this RAI, the following conservatisms have been identified by the licensee that may be credited to offset any potential impact of the 2-pump local flow characteristics:

5. In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the 2-pump coastdown.

6. In RETRAN, the transient nuclear power prediction assumes a minimum scram reactivity worth based upon the most bottom-peaked axial power distribution. In VIPRE, the DNBR calculations are based on a top-peaked axial power distribution.

7. In VIPRE, the peak power assembly with the peak rod at the radial peaking factor design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

8. In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate the radial peaking factor corresponding to the SAL DNBR. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

The NRC staff's safety evaluation (Ref. 6) concluded that, in combination with the composite transient (that superimposes the 2-pump coastdown flow on the peak power excursion MSLB case), Items 1, 2, and 3 above compensate for any nonconservative aspects of the thermal-hydraulic model relative to the 2-pump coastdown inlet flow distribution and cross-flow characteristics. These modeling assumptions assure that the minimum DNBR calculations remain conservative. If the calculated minimum DNBR was below the SAL DNBR, item 4 could have been credited to assure that the predicted number of failed fuel rods remains conservative.

These conservative assumptions and modeling techniques remain part of the 42-percent SGTP analysis. Table 5.1.5-1a of Reference 4 provides the sequence of events for the limiting pre-trip MSLB with FFBT case (3.2 ft^2 break size for a moderator density coefficient of 0.43 Δk/gm/cc). A review of this table indicates that the hot channel minimum DNBR remains above the 95/95 DNB design criteria for the duration of the event, thus, assuring no fuel rod failures due to DNB. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective design limits during each reload design. Based upon the conservative nature of the composite event and the conservatism identified above, the NRC staff concludes that the analysis of the pre-trip MSLB with FFBT event is acceptable.

Table 5.1.5-1b of Reference 4 provides the sequence of events for the pre-trip MSLB with concurrent LOOP. The credited reactor protection function, a low RCS flow trip, includes harsh environmental effects (due to inside containment steam ruptures). Because the radial and axial peaking factors and pin power distributions are dependent on the cycle-specific loading pattern, the minimum DNBR and number of failed fuel rods (i.e., minimum DNBR is less than SAL DNBR) are calculated during each reload design. The total number of failed fuel rods will remain below 2.5 percent, which is less than the minimum value (10.5 percent, as indicated in

Section 5.4.5.1 of Reference 4) used to calculate the dose consequences that reach the 10 CFR Part 100 dose limits during the pre-trip MSLB event.

In response to an RAI regarding DNB propagation (RAI-6 of Ref. 2), the licensee stated that DNB propagation does not occur and margin to clad strain increases. Hence, the propagation of fuel rod failures due to cladding ballooning is avoided. The NRC staff finds that the DNB propagation has been adequately addressed by the licensee. Based upon review of the limiting case presented in the amendment request (Ref. 4) and the licensee's commitment to limit fuel failure and associated radiological consequences to below 10 CFR Part 100 requirements, the NRC staff concludes that the analysis of the pre-trip MSLB with concurrent LOOP event is acceptable.

In addition, the licensee demonstrated that the pre-trip MSLB with FFBT event did not exceed the SAL DNBRs, satisfying acceptance criteria for moderate frequent events. Therefore, the NRC staff agreed with the licensee that the analysis pre-trip MSLB with FFBT can be credited to bound the increased main steam flow events discussed in Sections 5.1.2 and 5.1.4 of the St. Lucie Unit 2 licensing report (Ref. 4).

According to St. Lucie Unit 2 UFSAR Section 15.1.5.4, the pre-trip MSLB was analyzed to assure that a coolable geometry is maintained and that site boundary doses do not exceed 10 CFR Part 100 requirements. Coolable geometry is maintained by satisfying DNB propagation criteria and by demonstrating that incipient fuel melting does not occur. Site boundary doses are maintained within acceptable limits by demonstrating that the amount of fuel rod failures (due to DNB) do not exceed the assumption in the docketed dose calculation.

Based upon the above review, the NRC staff concludes that the results of the limiting pre-trip MSLB events are acceptable.

3.4.2.5 Post-trip Main Steam Line Break

Section 5.1.6 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the post-trip MSLB event. This analysis is supplemented by responses to the NRC staff's RAIs in Reference 2.

The Westinghouse computer codes RETRAN, ANC, and VIPRE were used to simulate the post-trip MSLB event. These codes have been previously reviewed and approved and their application is consistent with the post-trip MSLB methodology recently reviewed and approved as part of the 30-percent SGTP license amendment (Ref. 6) as reflected in the latest amendment to Section 15.1.6 of the St. Lucie Unit 2 UFSAR (Ref. 21).

Similarly, the post-trip MSLB methodology was employed in the selection of initial conditions and assumptions that maximize the return-to-power experienced during the event. The limiting scenario was identified as the double-ended rupture of a main steam line at hot zero-power subcritical conditions (corresponding to EOL shutdown margin requirements) with offsite power available.

No RETRAN transient simulations were executed as part of the 42-percent SGTP licensing report (Ref. 4). Instead, the RETRAN statepoints from the 30-percent SGTP post-trip MSLB case (Ref. 6) were modified to make them applicable to the 42-percent SGTP cases by reducing the flow from 335,000 gpm to 300,000 gpm. In response to an RAI regarding the conservatism of the ANC core physics calculation (RAI-7 of Ref. 2), the licensee stated that the use of the 30-percent SGTP case results in a higher power level, higher inlet temperatures, and lower boron concentrations than would be predicted at the lower RCS flow condition. Note that the transient simulation conservatively models zero SGTP and zero fouling of the SG tubes. The NRC staff agrees that the use of the 30-percent SGTP statepoints with the manual adjustment in RCS flow is conservative for the 42-percent SGTP operating conditions.

Table 5.1.6-1 in Reference 4 provides the sequence of events for the limiting post-trip MSLB case. Since the RETRAN simulation was not run, the sequence of events remains the same as UFSAR Table 15.1.6-1 values (Ref. 21), except for the cycle-specific DNBR and power peaking. The SLB is an ANS Condition IV event that must satisfy dose limit requirements. However, the licensee has conservatively analyzed this event to satisfy ANS Condition II event criteria that preclude fuel damage. A review of Table 5.1.6-1 indicates that the DNBR and peak linear heat rate limits are not exceeded. Future reloads will need to assure, based upon cycle-specific core physics predictions, that these limits would not be exceeded. Based upon the above review, the NRC staff concludes that the results of the post-trip MSLB event are acceptable.

3.4.2.6 Decreased Heat Removal by the Secondary System

The events with a decrease in heat removal by the secondary system include (1) turbine trip, (2) loss of normal feedwater flow (LONF), (3) LOOP, (4) loss of condenser vacuum (LOCV), (5) ASGTs, and (6) feedwater line break (FLB). These events are characterized by a rapid reduction in heat removal capability of SGs. The loss of heat removal capability results in a rapid rise in the SG's secondary system pressure and temperature, and a subsequent increase in the RCS primary system pressure and temperature. Reactor trip and actuation of secondary and primary safety valves mitigate the effects of the primary-to-secondary system power mismatch during these events. The severity of these events is increased if the primary-to-secondary system power mismatch is increased. The licensee analyzed Event-4, LOCV, with initial conditions to bound Event-1, Turbine trip, and provided the results of analysis in Section 5.1.10 of Reference 4. The licensee did not analyze Event-2, LONF, and Event-3, LOOP, and provided its rationale in Section 5.1.9 of Reference 4 for these two unanalyzed events that are bounded by other moderate-frequency events. The licensee analyzed Event-5, ASGT, and Event-6, FLB, and provided the results of analyses in Sections 5.1.11 and 5.1.12 of Reference 4, respectively.

Section 15.2 of the SRP indicates that an acceptable analysis of the decreased heat removal by the secondary system events (heatup events) should comply with the requirement of the Three Mile Island (TMI) Action Plan, Item II.E.1.2 as it relates to the performance requirements of the auxiliary feedwater (AFW) system for long-term-cooling (LTC) during the events. Recent licensing experience indicated that a CE plant licensee's original analysis addressing the II.E.1.2 requirements did not consider the effect of SG blowdown flow, and its reanalysis showed that the SG blowdown flow rate has significant effect on the LTC analysis for the heatup events. Since St. Lucie Unit 2 is a CE-designed plant, the NRC staff requested the licensee to provide information to address the effect of the SG blowdown flow on the LTC analysis for heatup events. In response, the licensee indicated (in RAI-9 response of Ref. 2) that the AFW system evaluation analyses performed to meet the requirements of TMI Action item II.E.1.2 are described in UFSAR Section 10.4.9A.

Both the loss of main feedwater and the feedwater line break events with and without loss of offsite power were analyzed for performance of the AFW system from LTC decay heat removal considerations. The licensee reviewed the analyses of the events described in UFSAR Section 10.4.9A and indicated that the analyses were performed using conservative methods and assumptions, such as initial power of 102 percent, setpoints and uncertainties applied in the conservative direction, and minimum AFW flow with a conservative delay time. The licensee indicated that the SG blowdown flow was not assumed in the analyses.

For the four cases analyzed, the analyses were performed up to 30 minutes after initiation of the events. The results showed that the AFW system provides adequate capacity for decay removal and the minimum SG inventory for the limiting case, the feedwater line break with offsite available, is greater than 18,000 pounds mass (lbm) in the unaffected SG. In addressing the SG blowdown effect on the AFW system performance analysis in the UFSAR Section 10.4.9A, the licensee assumed that the SG blowdown flow is 6 lbm/sec-SG and the operator takes 30 minutes after initiation of the event to close the isolation valve and terminate SG blowdown flow. The total blowdown flow for a flow rate of 6 lbm/sec in 30 minutes is about 10,800 lbm. With the SG blowdown operable for 30 minutes, the minimum SG inventory of 18,000 lbm will decrease but still maintain margin (greater than 7,000 lbm) to SG dryout. Further, the reduction in decay heat corresponding to the operation at 89 percent power will result in additional margin for these event. The NRC staff found that the assumed blowdown flow rate of 6 lbm/sec in the assessment is adequate because it is consistent with the SG blowdown design flow rate. The results of the assessment showed that, with consideration of the effect of the SG blowdown flow, the unaffected SG will not dry out during the events. These results provide reasonable assurance that the analyses in the UFSAR Section 10.4.9A demonstrate significant margin to SG dryout in the unaffected SG to account for SG blowdown flow for 30 minutes.

The NRC staff also reviewed acceptability of the assumed isolation of SG blowdown within 30 minutes based on the need for operator manual action. The licensee indicated that the requirement to isolate SG blowdown is contained in emergency operating procedure 2-EOP-06, "Total Loss of Feedwater." The control room operators are trained on this procedure in the plant simulator and the licensed operator training program has a simulator performance measure to ensure that the operators isolate SG blowdown within 30 minutes following a loss-of-feedwater event. In reviewing the proposed amendment and the St. Lucie Unit 2 UFSAR, the NRC staff determined that no new operator actions were introduced regarding isolation of the affected SG in this event. The NRC staff concluded that the procedural controls and training performance measures provide adequate assurance that SG blowdown isolation will be accomplished within 30 minutes following a loss-of-feedwater event. With the acceptable operator action time for SG blowdown isolation, the NRC staff agreed with the licensee that the decay heat removal by the AFW system will be maintained and, therefore, the NRC staff concluded that the SG blowdown flow effect is satisfactorily addressed by the licensee.

3.4.2.7 Turbine Trip and Loss of Condenser Vacuum

Signals such as generator trip, low condenser vacuum, manual trip, and reactor trip may initiate the turbine trip event. Following a turbine trip, the turbine stop valves rapidly close, and steam flow to the turbine abruptly stops. The loss of steam flow results in a rapid increase in secondary system pressure, and temperature, as well as a reduction of the heat transfer rate in the SGs, which, in turn, causes the RCS primary system pressure and temperature to rise.

LOCV may result in a turbine trip and prevent steam from dumping to the condenser. The licensee analyzed this event as a turbine trip from 89 percent of RTP with a simultaneous loss of feedwater to both SGs due to low suction pressure on the feedwater pumps. In addition, the licensee assumed that the atmospheric dump valves and the steam dump and bypass system valves were unavailable. These assumptions minimize the amount of cooling and maximize the RCS and secondary peak pressure. Because the licensee assumed that steam dump and feedwater flow are unavailable in the LOCV analysis, no additional adverse effects will result for the turbine trip event caused by the LOCV. Therefore, the LOCV analysis bounds the turbine trip event. The reactor trip signals of high pressurizer pressure or thermal margin/Low pressure (TM/LP) provides protection against undesirable conditions during the LOCV event.

The licensee performed the analysis of the LOCV event using RETRAN for the transient response calculation and VIPRE for the DNBR calculation. The licensee analyzed three cases for the LOCV event. One case calculated the minimum DNBRs. The other two cases calculated the peak RCS primary and secondary pressures, respectively. A maximum of 42 percent of the SG tubes were assumed to be plugged. For the case analyzed to show that the SAL DNBRs were not exceeded, automatic pressurizer control was modeled and safety valves were modeled assuming a minus 3 percent setpoint tolerance, consistent with St. Lucie Unit 2 TSs. The pressurizer pressure control will actuate the pressurizer spray that causes the pressurizer pressure to decrease, and the lower safety valve setpoint will open the safety valves at a lower pressure and limit the pressure increase. The combined effects result in lower RCS pressures, which, in turn, result in lower DNBRs. In the DNBR calculations, the initial reactor power, RCS pressure and temperature were assumed to be at their nominal values, and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A.

For the cases analyzed to show that the peak pressure was within 110 percent of the design pressure, initial core power and RCS temperature were assumed at the minimum values consistent with initial power assumed, including the associated measurement and calibration uncertainties. Initial pressurizer pressure was assumed at the minimum value corresponding to 89-percent power operation. The combined effects of the minimum core power, RCS temperature, and pressurizer pressure will delay reactor trip on high pressurizer pressure and result in a higher peak pressure. In addition, for the RCS primary system pressurization case, no credit was taken for the effect of the pressurizer spray or power-operated relief valves (PORVs) in reducing the primary RCS pressure. Pressurizer safety valves were modeled assuming a plus 3 percent setpoint tolerance (consistent with the St. Lucie Unit 2 TSs) to open the safety valves at a higher pressure. For the SG shell side pressurization case, credit was taken for the effect of the pressurizer spray in reducing the primary pressure, thus, delaying the actuation of the reactor trip signal. Delaying the reactor trip increases the energy input to the secondary system, and results in a higher secondary system pressure. Consistent with TS 3/4.4.4, one of the two PORVs was assumed to open on the high pressurizer pressure trip signal. For all cases analyzed, no credit was taken for AFW flow, since stabilized plant conditions would be reached before AFW initiation was normally assumed to occur for at-power cases.

The NRC staff finds that (1) the analysis uses acceptable methods and adequate assumptions to maximize the peak pressure or minimize the lowest DNBR, (2) the calculated RCS primary and secondary system pressures are within 110 percent of the design pressure, and (3) the calculated minimum DNBR is within the SAL DNBRs. Therefore, the NRC staff concludes that the LOCV analysis meets the acceptance criteria of SRP 15.2.3, and the analysis is acceptable.

3.4.2.8 Loss of Normal Feedwater and Loss-of-Offsite Power

Section 5.1.9 of the licensing report (Ref. 4) documents the rationale for why the LONF and LOOP events are bounded by other events. A LONF event may be caused by breaks in the main feedwater system piping upstream of the main feedwater check valves, feedwater pump failures including loss of ac power or loss of motive steam, or spurious closure of main feedwater isolation valves and regulating valves. Following a LONF, the SG water inventory decreases as a consequence of continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater leads to a reactor trip on a low SG level signal. Following the reactor trip, the rate of heat generation in the RCS may exceed the heat removal capability of the SGs. The power generation and heat removal mismatch will result in an increase in SG pressure, RCS pressure, RCS temperature, and pressurizer-water level.

A LOOP event may be caused by a complete loss of the offsite grid, accompanied by a turbine-generator trip. This event is identical to the LONF event except that a loss of power to the RCPs occurs simultaneously with the LONF.

The licensee indicated that, with respect to a decrease in DNBRs, the LONF and LOOP events are bounded by the complete loss of flow (LOF) event discussed in Section 5.1.14 of Reference 4. For the LONF event, the RCS temperature before a reactor trip increases slightly, while no appreciable power increase occurs and the full RCS flow remains available. The effect of the reduction in RCS flow on the DNBR for the complete LOF event is more significant than the effect of increase in the RCS temperatures for the LONF event before reactor trip. After the reactor trip, the power and RCS temperature decrease while the full RCS flow remains available, the DNBR will increase significantly during the LONF.

As for the LOOP event, the RCPs will coast down immediately in addition to the loss of feedwater flow. This event is identical to the LOF event except that the reduction in feedwater flow will reduce the cooling of the RCS primary system which, in turn, results in an increased RCS pressure, thereby increasing the DNBR in comparison to the LOF analysis. The increase in SG primary side exit temperature will not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the minimum DNBR for the LOOP event is bounded by that of the LOF event.

With respect to overpressurization, the LOCV event discussed in Section 5.1.10 of Reference 4 will bound either the LONF or LOOP event because the LOCV event causes a Turbine trip with the LONF. The net effect of the Turbine trip and LONF for the LOCV event is a total loss of RCS secondary system heat sink, which results in the greatest challenge to RCS primary and secondary system pressurization. Therefore, the LOCV event remains the limiting event in terms of the peak RCS primary and secondary system pressures.

Based on the above discussion, the NRC staff agrees with the licensee that the consequences of the LONF and LOOP events are bounded by the analyses of the LOCV and LOF events, which were found acceptable (as discussed in Sections 3.4.2.7 and 3.4.2.11 of this evaluation, respectively). Therefore, the NRC staff concludes that the consequences of the LONF and LOOP events are acceptable.

3.4.2.9 Asymmetric SG Transients

Section 5.1.11 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of the ASGTs. The ASGTs that affect a single SG are loss of load to one SG, excess load to one SG, loss of feedwater to one SG, and excess feedwater to one SG. The licensee analyzed the loss of load to one SG that is the limiting ASGT identified in the UFSAR. The licensee modeled this event as an inadvertent closure of the main steamline isolation valve to one SG. During the transient, the SG's pressure and temperature increase until the opening pressure setpoint of the MSSVs is reached. As a result of the steam relieved through the MSSVs, the pressure in the affected SG decreases and stabilizes at the MSSV setpoint pressure. The unaffected SG continues to supply steam to the turbine. The steam flow from the unaffected SG results in an overcooling of the cold legs associated with the unaffected loop. The increase in the core inlet temperature from the affected loop in combination with the decrease in core inlet temperature from the unaffected loop results in a large core temperature asymmetry. The asymmetric core temperature distributions result in an increase in the radial and axial peaking in the core, causing a challenge to the design DNBR safety limit. The high SG differential pressure reactor trip provides protection against undesirable conditions.

The licensee analyzed this event using RETRAN to calculate the core average heat flux, core pressure and core inlet temperature. The core radial and axial peaking factors were determined using the thermal-hydraulic condition from the transient analysis as input to the ANC nuclear core models. VIPRE was used to calculate the heat flux and DNBR transients based on the nuclear power, and core temperature, and pressure from RETRAN. In the DNBR calculations, the initial reactor power, temperature and pressure were assumed to be at values consistent with 89-percent of RTP, and the initial RCS flow was assumed to be at the minimum flow rate of 300,000 gpm. Uncertainties in initial conditions were included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A. The analysis assumed reactivity feedback coefficients that maximized the increase in nuclear power prior to the reactor trip. These reactivity coefficients were weighted to the RCS loop associated with the unaffected SG to maximize the power increase.

The analysis assumed that the automatic pressure control system was operable during the event. Thus, full credit was taken for the effect of the pressurizer spray in limiting any primary pressure increase above the initial pressure. This results in a lower RCS pressure that, in turn, results in lower DNBRs. The analysis also assumed that concurrent termination of feedwater flow to the affected SG occurred to bound any potential response of the feedwater system. Feedwater isolation to the affected SG will result in an increase in the reactor vessel inlet temperature asymmetry during the event, resulting in a lower minimum DNBR.

The licensee analyzed two cases: with zero-percent SGTP and with 42-percent SGTP. The results showed that the calculated minimum DNBR of 2.01 for the limiting case (the 42-percent SGTP case) was significantly greater than the SAL DNBRs.

During the review, the NRC staff requested the licensee to address the effect of the asymmetric SGTP in each SG. In its response to RAI-11 (Ref. 2), the licensee indicated that the maximum SGTP asymmetry is 7 percent. In the worst-case scenario, this would correspond to 42-percent

SGTP in one SG and 35-percent SGTP in the other SG. The licensee indicated that the RCS flow asymmetry resulting from a 7-percent plugging difference is small - about 1.4 percent. The NRC staff agreed with the licensee that the RCS flow asymmetry is small and is not significant to the result of the ASGT analysis.

The NRC staff finds that the analysis uses acceptable methods and reasonable assumptions. The results of the analysis for the limiting case show that the minimum DNBR remains significantly above the SAL DNBRs, satisfying the acceptance criteria of the SRP Section 15 for moderate-frequency events. Therefore, the NRC staff concludes that the analysis is acceptable.

3.4.2.10 Feedwater Line Break

The Westinghouse computer code RETRAN was used to simulate the FLB event. RETRAN has been previously reviewed and approved and its application is consistent with the FLB methodology recently reviewed and approved as part of the 30-percent SGTP license amendment (Ref. 6) as reflected in the latest amendment to Section15.2.8 of the St. Lucie Unit 2 UFSAR (Ref. 21).

Similarly, the FLB methodology was employed in the selection of initial conditions and assumptions which maximize the peak RCS and secondary pressure experienced during the events. Three distinct scenarios were evaluated:

9. Small FLB ($\leq$ 0.2 ft^2) with a Single Failure (FFBT at Reactor/Turbine Trip)

10. Large FLB (>0.2 ft^2)

11. Large FLB (>0.2 ft^2) with a Single Failure (FFBT at Reactor/Turbine Trip)

Using conservative assumptions and initial conditions consistent with that of the approved FLB methodology, the licensee performed a break spectrum analysis to identify the limiting break with respect to both peak primary and peak secondary pressure. The results of this sensitivity study are provided in Tables 5.1.12-1 and 5.1.12-2 of Reference 4. A review of Table 5.1.12-1 indicates that the limiting break size with respect to peak primary pressure is 0.31 ft^2 and that all break sizes in combination with a FFBT satisfy the 110 percent of design pressure criterion. Table 5.1.12-3 provides the sequence of events for this limiting break. A review of Table 5.1.12-2 indicates that the limiting break size with respect to peak secondary pressure is 0.10 ft^2 and that all break sizes satisfy the 110 percent of design pressure criterion. Table 5.1.12-4 provides the sequence of events for this limiting break.

In response to an RAI regarding inoperable MSSVs (RAI-1 of Ref. 2), the licensee stated that TS 3.7.1.1 operational limits with inoperable MSSVs have been validated at the 42-percent SGTP operating conditions for the limiting transients.

In response to an RAI regarding the DNB design basis (RAI-8 of Ref. 2), the licensee stated that the DNB degradation experienced during a FLB with and without FFBT is bounded by a complete loss of flow event. Hence, no fuel failure would be experienced (see Section 3.4.2.11 of this safety evaluation). The licensee also noted that the FLB with coincident LOOP event is bounded by the pre-trip MSLB with coincident LOOP event with respect to DNB fuel failures and that the dose consequences remain within a small fraction of 10 CFR Part 100 limits. The NRC staff agreed that the FLB event will be bounded by the loss of flow and pre-trip MSLB events, as stated by the licensee.

Following approved models and methods, the licensee has demonstrated that each of the different FLB scenarios meets its respective peak-pressure limits. Further, any potential dose consequences remain within acceptable limits. Based upon the above review, the NRC staff concludes that the analysis of the FLB event is acceptable.

3.4.2.11 Decrease in Reactor Coolant Flow Rate

A mechanical or electrical failure of RCPs or a fault in the electrical bus supplying power to the RCPs bus may cause the loss of RCS flow. A decrease in reactor coolant flow occurring while the plant is at power results in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result, potentially violating SAL DNBRs. Reactor protection and safety systems are actuated to mitigate the transient. The credible loss of RCS flow events consist of the 1-out-of-4, 2-out-of-4 and 4-out-of-4 RCP trip events. The licensee analyzed the total loss of RCP flow (the 4-out-of-4 RCP trip event), which is the limiting event identified in the AOR (Ref. 21), and provided the results of the event analysis in Section 5.1.14 of Reference 4 for the NRC staff to review.

The licensee analyzed the total loss of RCP flow event using the following computer codes: RETRAN (calculated the nuclear power, the RCS temperature and pressure, and the core flow during the transient); and VIPRE (calculated the heat flux and DNBRs based on the nuclear power and RCS temperature, pressure, and flow from RETRAN). The DNBR calculations were based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, temperature, and pressure were assumed to be at values consistent with 89-percent of RTP; the initial RCS flow was assumed to be at the minimum flow rate of 300,000 gpm; and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP. The licensee also assumed a large absolute value of the Doppler power coefficient with the most positive moderator temperature coefficient corresponding to 89-percent power operation. These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached and are, therefore, conservative. The analysis assumed a limiting DNB axial power shape in VIPRE for the calculation of DNBR. This shape provides the most limiting minimum DNBR for the LOF event. A maximum, uniform, SGTP level of 42 percent was assumed in RETRAN analysis. The effect of RCS flow loop asymmetry because of loop-to-loop SGTP imbalance is small and is not significant enough to be considered for the LOF event in which all RCPs experience a flow coastdown. The reactor trip was assumed to occur when the core flow reached the low-flow trip setpoint.

The results of the analysis show that the calculated DNBR will remain above the SAL DNBRs, assuring that no fuel damage is predicted to occur. With respect to overpressurization, the LOCV event discussed in Section 5.1.10 of Reference 4 will bound the LOF event because the LOCV event causes a Turbine trip with the LONF. The net effect of the Turbine trip and LONF for the LOCV event is a total loss of RCS secondary system heat sink, which results in the greatest challenge to RCS primary and secondary system pressurization. Therefore, the LOCV event remains the limiting event in terms of the peak RCS primary and secondary system pressures, which are shown to be less than 110 percent of the design pressures. The NRC staff agrees with the licensee that the maximum RCS primary and secondary system pressures during the LOF event will be bounded by that of the LOCV event and also remain below 110 percent of their respective design pressure. Therefore, the NRC staff determined that the analysis meets the acceptance criteria of SRP Section 15.3.2 with respect to the integrity of the RCS pressure boundary and fuel rods, and thereby, concludes that the analysis is acceptable.

3.4.2.12 Total Single RCP Shaft Seizure/Sheared Shaft

Section 5.1.15 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of total single RCP shaft seizure/sheared shaft events. The events postulated are an instantaneous seizure of the rotor or the break of the RCP shaft. During the transient, flow through the affected loop is rapidly reduced, leading to a reactor trip on a low-flow signal. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer that could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure (locked rotor) event than that in a pump shaft break event because the fixed shaft in the locked rotor event causes greater flow resistance than a free-spinning impeller in the shaft break event earlier during the transient, when flow through the affected loop is in the forward direction. 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. Because peak pressure, cladding temperature, and DNB occur very early in these transients, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Therefore, the licensee analyzed the limiting case, the locked rotor event.

The licensee used RETRAN for calculation of the loop and core flow rate, nuclear power, RCS pressure, and temperature during the event. The licensee used VIPRE for the DNBR calculation. The DNBR calculations were based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, RCS pressure and temperature were assumed to be at values consistent with 89-percent power operation; the RCS flow was assumed to be at the value of thermal design flow (300,000gpm); and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP. In the RCS pressure and temperature calculations, the licensee assumed maximum values for the initial power level, RCS pressure and temperature with the inclusion of the measurement uncertainties to maximize the calculated peak RCS pressure. The licensee also assumed a large absolute value of the Doppler power coefficient with the most positive moderator temperature coefficient for 89-percent power operation. These assumptions maximize the core power and are, therefore, conservative. Following the locked rotor, reactor trip is initiated on an RCS flow-low signal.

The results of the pressurization calculation show that the calculated peak RCS pressure is 2637 pounds per square inch atmospheric (psia), which meets the acceptance criterion of less than 2750 psia (110 percent of the design pressure).

In the licensing report (Ref. 4), the licensee has opted to use in the DNBR analysis the mechanistic LOOP as a result of grid collapse induced by the plant trip. In this mechanistic approach, the licensee used a delay time of 3 seconds between the turbine trip and a LOOP. The delay time of 3 seconds is consistent with the value used in the AOR (Ref. 21) for St. Lucie Unit 2 that also applied the mechanistic LOOP approach, and therefore, is acceptable. A LOOP causes a simultaneous LONF, LOCV, and coastdown of all RCPs. The analysis performed previously (Ref. 21) for LOOP scenarios, on the nonsafety 6.9 kv RCP buses, showed that the immediate loss of one 6.9 kv bus and, thus, loss of power to the associated two RCPs due to plant-centered failure following a reactor/turbine/generator trip is possible as a result of a plant-centered component failure. In addressing the effect of the immediate loss of two RCPs due to a plant-centered component failure (such as FFBT), the licensee performed the analysis of the locked rotor event with an FFBT (resulting in the immediate loss of two RCPs following turbine trip). The approach of including the effect of an FFBT is consistent with that included in the AOR (Ref. 21) and is, therefore, acceptable.

Consistent with that used in the AOR, additional assumptions used in the DNBR analysis were: (1) in RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the 2-pump coastdown; (2) in VIPRE, the peak power assembly with the peak rod at the radial peaking factor design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly; (3) in estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate the radial peaking factor corresponding to the SAL DNBR. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

Items (1) and (2) above compensate for non-conservative aspects of the thermal-hydraulic model relative to the 2-pump coastdown inlet flow distribution and cross-flow characteristics. These conservative modeling assumptions assure that the minimum DNBR calculations remain conservative. If the calculated minimum DNBR was below the SAL DNBR, item (3) could have been credited to assure that the predicted number of failed fuel rods remain conservative. Further, the results of the DNBR analysis show that the total percentage of fuel rods calculated to experience DNB is less than 1 percent of the fuel in the core, which is significantly less than the minimum value (2.5 percent) used in the dose consequences analysis for this event.

During the review, the NRC staff requested that the licensee provide information related to the effect of a flow asymmetry resulting from asymmetric tube plugging on the DNB analysis. In response (RAI-12 response of Reference 2), the licensee indicated that a very conservative penalty for loop-to-loop RCS flow asymmetry was applied to the limiting locked rotor event statepoints. RCS flow asymmetries that would result from the maximum allowed plugging asymmetry of 7 percent would be about 1.4 percent, which is bounded by the assumed penalty applied to the DNB analysis that was developed for an RCS flow asymmetry of 5 percent for a Westinghouse designed 4-loop plant.

Based on its review, the NRC staff found that the calculated maximum RCS pressure remains less than 110 percent of the design pressure, and the total percentage of rods calculated to experience DNB (less than 1 percent of the total number of the fuel rods) is small and is less than the value assumed in the acceptable dose consequence analysis for this event. Therefore, the NRC staff concludes that the analysis of the locked RCP rotor event meets the acceptance criteria of SRP Section 15.3.3 and is acceptable.

3.4.2.13 Uncontrolled Control Element Assembly Bank Withdrawal at Power

Section 5.1.16 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of the uncontrolled CEA bank withdrawal at power. A CEA bank withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. Such an event causes an increase in fuel and coolant temperature as a result of the core-turbine power mismatch. Reactor trips, including the variable high power (VHP) trip, high pressurizer pressure (HPP) trip, TM/LP trip and high local power density trip, provide plant protection.

The NRC staff determined that the licensee performed the analyses with acceptable methods: the RETRAN code calculated the nuclear power transient, and the RCS pressure and temperature transients; the FACTRAN code calculated the heat flux based on the nuclear power from RETRAN; and the VIPRE code calculated the DNBR using heat flux from FACTRAN and the flow, inlet core temperature, and pressure from RETRAN. The VHP trip was assumed to occur at 102 percent of RTP. As indicated in the licensee's response to RAI-3 (Ref. 2), this value of the VHP trip setpoint is consistent with the delta power trip setpoint, which is set at 9.61 percent of RTP, as specified in the TSs. Adding the 9.61 percent of RTP to the maximum power of 89 percent power results in a power level that is bounded by a power level of 102 percent of RTP. The NRC staff, therefore, determined that using a setpoint of 102 percent of RTP was conservative and acceptable for modeling the VHP trip setpoint.

The HPP trip was assumed to occur when the pressurizer pressure reached 2415 psia. The TM/LP trip was modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index. The ΔT-power (a power increase above the initial power level) feature of the VHP trip was assumed to trip the reactor when the ΔT-power reached the setpoint of 30 percent of RTP for the cases initiated from less than 89-percent power (20, 50, and 65 percent of RTP). This 30-percent ΔT-power trip setpoint included setpoint uncertainties, power measurement uncertainties, and accounts for excore decalibration due to CEA withdrawal. For the 89-percent power case, the reactor was assumed to trip when the ΔT-power reached the setpoint of 11 percent of RTP. In the DNBR calculations, the initial reactor power, RCS pressure and temperature were assumed to be at values corresponding to 89-percent power operation, the RCS flow was assumed to be at the value of thermal design flow rate of 300,000 gpm, and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP (Ref. 20).

The licensee analyzed cases with both minimum and maximum reactivity feedback coefficients, and performed a sensitivity study of the effects of initial power levels (20, 50, 65, and 89 percent of RTP) and reactivity insertion rates that bound the maximum reactivity insertion rate of 53 percent millirho per second (pcm/sec) resulting from the simultaneous withdrawal of two control rod banks.

The analyses use the previously NRC-approved methods and adequate values of plant parameters. The results of the analyses showed that with the combination of the VHP, HPP, and TM/LP trips, the DNBRs do not fall below the SAL DNBRs and the peak heat generation rate is less than the limiting value for fuel melting for all cases, assuring that fuel integrity and adequate fuel cooling are maintained. The calculated peak RCS pressure is less than the acceptance criterion of 110 percent of the design pressure. The NRC staff finds that the analyses meet the acceptance criteria of SRP Section 15.4.2 with respect to fuel integrity and

RCS pressure boundary limits. Therefore, the NRC staff concludes that the analyses are acceptable.

3.4.2.14 Uncontrolled CEA Withdrawal From a Subcritical Condition

Section 5.1.17 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of the uncontrolled CEA bank withdrawal from a subcritical condition. A CEA withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The VHP trip and the rate-of-change of power-high trip provide protection against this event.

The licensee used TWINKLE in the analysis for the average power generation calculation, FACTRAN for the hot rod heat transfer calculation, and VIPRE for the DNBR calculation. The DNBR calculation was based on the previously approved STDP, which is the traditional design method with parameter uncertainties applied deterministically in the limiting direction. In the DNBR calculation, the RCS flow rate was based on the thermal design flow of 300,000 gpm at a reduced power of 89 percent of RTP, and the RCS pressure was the nominal pressure minus the uncertainty. Since the event was analyzed from hot-zero power, the steady-state STDP uncertainties on core power and RCS average temperature were not used in defining the initial conditions. The analysis assumed a conservatively low value for the Doppler power defect and the maximum value for the moderator temperature coefficient to maximize the peak heat flux. Reactor trip was assumed to occur on the VHP trip signal with the setpoint of 35 percent of RTP, which included a 20-percent uncertainty. The analysis assumed a maximum positive reactivity insertion rate of 40 pcm/sec. This rate exceeds that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed (30 inches per minute). The maximum reactivity insertion rate of 40 pcm/sec will be confirmed by the licensee for each reload cycle. The DNBR calculation assumed the most limiting axial and radial power shapes associated with the two highest-worth banks in their highest-worth position. The initial power level was assumed to be below the power level expected for any shutdown conditions (10^{-9} fraction of nominal power). The combination of the highest reactivity addition rate and lowest initial power produces the highest peak heat flux, resulting in a lowest calculated minimum DNBR, and thus, is conservative. Both Uranium oxide-only fuel and fuel with up to 8 weight-percent Gadolinia were considered in the analysis. The results of the analyses show that the DNBRs do not fall below the SAL DNBRs, the peak heat generation rate is less than the limiting value for fuel melting and the calculated peak RCS pressure is less than 110 percent of the design pressure.

The NRC staff has reviewed the assumptions related to the reactivity worth and reactivity coefficients used in the analysis and found that they maximize the calculated heat flux, thereby minimizing the calculated DNBRs and, therefore, are conservative. The NRC staff has reviewed the calculated consequences of this event and found that they meet the requirements of GDC 10, in that the SAL DNBRs are not exceeded. The licensee also meets the requirements of GDC 20, in that the reactivity control system can be initiated automatically so that SAL DNBRs are not exceeded. In addition, the licensee meets the requirements of GDC 25, in that a single malfunction in the reactivity control system will not cause the SAL DNBRs to be exceeded. Therefore, the NRC staff concludes that the analysis satisfies the acceptance criteria of SRP Section 15.4.1 and is acceptable.

3.4.2.15 Control Element Assembly Drop Event

Section 5.1.18 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of a CEA drop event. A CEA drop event is defined as the inadvertent release of a single or subgroup of CEAs causing the CEA(s) to drop into the core. The occurrence of a single electrical or mechanical failure in a CEA drive mechanism would result in a CEA drop.

In this event, the core power initially decreases due to the insertion of negative reactivity resulting from the dropped control rod. Moderator and Doppler temperature feedback causes power to return to its initial level at a reduced RCS temperature and pressure condition. The event results in a localized increase in the radial peaking factor that causes DNBR to decrease. In cases where reactivity feedback does not offset the worth of the dropped CEA, a cooldown condition exits until a reactor trip is reached on a TM/LP (floor) or a low SG pressure signal.

The licensee analyzed a number of cases with a spectrum of dropped CEA worth from 100 to 1000 pcm initiated from 89 percent of RTP. The St. Lucie Unit 2 CEA drop detection system was assumed inoperable with no credit taken for the turbine runback feature. With a decrease in power, the turbine load was not reduced, but was assumed to remain the same as that before a CEA drop occurred. This resulted in power mismatch between the primary and secondary system leading to a cooldown of the RCS. In addition, the automatic withdrawal capability of the control element drive mechanism was disabled. The licensee used the NRC-accepted versions of the RETRAN, VIPRE and ANC computer codes to analyze the DNBR consequences for this event. The DNBR analysis assumed that the RCS flow was 300,000 gpm and the initial power level was at 89 percent of RTP, corresponding to the respective minimum flow and maximum power at the 42-percent SGTP conditions. The results of the analysis show that the minimum DNBR at 42-percent SGTP conditions is less severe than that of the current analysis for St. Lucie Unit 2 at 30-percent SGTP level conditions and it does not violate SAL DNBRs. The NRC staff finds that the analysis used the approved methods and showed that fuel damage will not occur. Therefore, the NRC staff concludes that the analysis is acceptable because it meets the acceptance criterion of SRP Section 15.4.3 with respect to the fuel cladding integrity.

3.4.2.16 Uncontrolled Boron Dilution

Section 5.1.19 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of an uncontrolled boron dilution event. Unborated water can be added to the RCS via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction that causes an unwanted increase in reactivity and a decrease in shutdown margin. The operator must stop this unplanned dilution before the shutdown margin is eliminated. Section 15.4.6 of the SRP suggests that at least 15 minutes is available from the time the operator is made aware of an unplanned boron dilution event to the time a total loss of shutdown margin (criticality) occurs during power operation, startup, hot standby, hot shutdown, and cold shutdown (Modes 1 through 5). A response time of 30 minutes is suggested during refueling (Mode 6).

As discussed in UFSAR 7.7.1.1.11, the boron dilution alarm system provides a direct indication of a boron dilution in process. In the case that the boron dilution alarm system is inoperable, the St. Lucie Unit 2 UFSAR contains requirements for the maximum frequency of RCS chemistry sampling. These sampling frequencies assure that the specified criteria are met so that sufficient time is available to the operators, from the detection of a dilution event until criticality is achieved, to mitigate the consequences of this event.

The licensee analyzed the boron dilution event to assure that the results meet the SRP 15.4.6 acceptance criteria for all Operational Modes. The analyses performed in support of the 42-percent SGTP application result in values of the maximum critical and initial boron concentrations with one, two, and three charging pumps operating. The maximum critical and initial boron concentrations are verified by the licensee every operating cycle as part of reload verification process.

The NRC staff confirmed that the licensee used assumptions in the analysis that will result in a conservative determination of the time available for operator or system response after detection of a born dilution event. Dilution flow rates used for analyses of each mode were based on the dilution source fluid conditions for reactor makeup water at 40 ^{0}F and 14.7 psia. The same method used in the AOR (Ref. 21) was used for the analysis. For Modes 3 , 4, and 6, the maximum flow from one, two, or three charging pumps was assumed as the dilution flow rate. For Mode 5, flow from one, two, or three charging pumps was assumed for cases with the water level at (or above) the hot-leg centerline, and flow from one charging pump was assumed for case with the water level at the bottom of the hot-leg. For the Mode 2 and Mode1 cases, the maximum capacity from three charging pumps was assumed for the dilution flow. The analyses used shutdown margins that were consistent with the minimum values required by the COLR for the shutdown modes. In maximizing the effect of the boron dilution, the analysis used the minimum amount of water in the RCS corresponding to 42-percent SGTP level conditions to mix with the incoming unborated water. The results, in Table 5.1.19-1 of Reference 4, show that the operator has at least 15 minutes for Modes 1 through 5, and 30 minutes for Mode 6 from an alarm announcing an unplanned boron dilution to the loss of shutdown margin. The results demonstrate compliance with the SRP 15.4.6 acceptance criteria with respect to the operator action time to terminate the boron dilution event. In addition, during the Mode 2 and Mode 1 operations, if the dilution is not secured, the reactor will be shut down by the high rate of change power trip for Mode 2, or by either the TM/LP, high pressure or variable high power trip for Mode 1.

The NRC staff reviewed (1) conditions at the time of the unplanned dilution, (2) causes, (3) initiating events, (4) the values of parameters used in the analytical model, and (5) results of the analyses. The NRC staff finds that the licensee's analyses have adequately accounted for the changes required for operation of the plant with a 42-percent SGTP level. The analyses use acceptable methods and conservative assumptions, and the results meet the acceptance criteria of SRP Section 15.4.6. Therefore, the NRC staff concludes that the boron dilution analysis is acceptable.

3.4.2.17 Control Element Assembly Ejection

Section 5.1.20 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of CEA ejection accidents.

The NRC staff evaluates the consequences of a CEA ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff reviews initial conditions, rod patterns and worth, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 28 for assuring that the effects of postulated reactivity accidents do not result in damage to the RCPB greater than limited local yielding and do not cause sufficient damage to significantly impair the capability to cool the core. Specific acceptance criteria, contained in SRP Section 15.4.8 and used to evaluate this accident, include: (1) reactivity excursions should not result in a radially averaged enthalpy greater than 280 calories per gram (cal/gm) at any axial location in any fuel rod, and (2) the maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the "Service Limit C" as defined in the ASME Boiler and Pressure Vessel Code.

The licensee analyzed the CEA ejection accident with the methods documented in Westinghouse topical report, WCAP-7588, Revision 1-A (Ref. 20), consistent with the methods used in the AOR (Ref. 21). The licensee analyzed two sets of cases for the accident, one initiated from full power (FP) that bounds the 89-percent of RTP condition and one initiated from zero power (ZP). The analysis of both of these cases used both beginning-of-cycle (BOC) and end-of cycle (EOC) kinetics. As indicated in Table 5.1.0-2 of Reference 4, the RCS flow was assumed at the thermal design flow of 300,000 gpm, corresponding to the minimum TS-required RCS flow for operation with SGTP levels up to 42 percent. Table 5.1.20-1 of Reference 4 also listed the values of other initial plant parameters (such as initial power level, ejected rod worth, and delayed neutron fraction). The analysis used minimum values for the delayed neutron fraction, minimum values of the Doppler power defect and maximum values of ejected CEA worth, which conservatively resulted in a higher nuclear power increase rate and maximum amount of energy deposited in the fuel following CEA ejection. The analysis also used a positive moderator temperature coefficient for the ZP-BOC case because this results in positive reactivity feedback and thus increases the magnitude of the power increase. The analysis credited the variable high power trip (a high setting for FP cases and lower setting for ZP cases) to trip the reactor. The results showed that the calculated values of maximum fuel pellet enthalpy for the four analyzed cases are 154.3 cal/gm for FP-BOC, 71.6 cal/gm for ZP-BOC, 144.9 cal/gm for FP-EOC and 81.0 cal/gm for ZP-EOC. These calculated values of peak fuel enthalpy fall below the limit of 280 cal/gm specified in SRP Section 15.4.8. The calculated values also fall within the Westinghouse-specified analysis limit of 200 cal/gm. In addition, based on the generic assessment in WCAP-7588, Revision 1-A that assumed an ejected rod worth that is approximately two times the value used in the St. Lucie Unit 2 rod ejection analysis (Ref. 6), and the peak pressure results documented in the current UFSAR, the NRC staff agreed with the licensee that the peak reactor pressure will be less than that which would cause stresses to exceed the "Service Limit C," and, thus, satisfies the guidance of SRP Section 15.4.8 with respect to the RCS pressure limit.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident, such as a CEA ejection event, at lower enthalpies than the limits currently specified in SRP 15.4.8. However, generic analyses performed by all of the reactor vendors have indicated that the fuel pellet enthalpy during reactivity insertion accidents will be much lower than the SRP 15.4.8 limits, based on their 3D neutronics calculations. For high burnup fuel that has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/gm.

The NRC staff has concluded that although the SRP 15.4.8 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated reactivity insertion accidents in operating plants with fuel burnups up to 60 GWD/MTU, such as St. Lucie Unit 2, will neither (1) result in damage to the RCPB, nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core as specified in current regulatory requirements. Based on the above discussion, the NRC staff determined that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed 42-percent SGTP. Therefore, the NRC staff concludes that the proposed operation at a maximum power of 89 percent of RTP with 42-percent SGTP is acceptable with respect to the rod ejection accident analysis.

3.4.2.18 Chemical and Volume Control System Malfunction

A CVCS malfunction may result in an event that increases RCS inventory. Operator actions, an electrical actuation signal, or a valve failure may cause the CVCS malfunction to occur. Section 5.1.21 of Reference 4 presents the results of the limiting case, the CVCS malfunction initiated from 89-percent of RTP with an assumed single failure caused by an erroneous low-low level signal that actuates a second charging pump and closes the letdown flow control valve to its minimum position. This initiating event assumption is consistent with the current event description in Section 15.5.2.2 of the UFSAR (Ref. 21). The licensee analyzed this event using the RETRAN code and established the following conditions to maximize the pressurizer water level:

1. The initial reactor power is at 89 percent of RTP with 2 percent uncertainty; the RCS pressure is 70 psi below the nominal pressure and the RCS temperature is at 3 ^{o}F above the nominal temperature.

2. Maximum charging flow is 49 gpm per pump for a total of 98 gpm for two charging pumps. This is reduced by 4 gpm for the RCP bleedoff flow, which results in an assumed total charging flow of 94 gpm.

3. The pressurizer sprays and heaters are operable.

4. The pressurizer safety valves are assumed to open at a setpoint with inclusion of minus 2 percent tolerance.

5. 42 percent of the SG tubes are assumed to be plugged.

6. The operators are alerted to the event by the pressurizer high level alarm at a setpoint of 70 percent of tap span.

7. Maximum reactivity feedback conditions are assumed.

The event was analyzed to address the concern of pressurizer overfill, so it was assumed to occur without increasing or deceasing the primary coolant initial boron concentration. The case of a CVCS malfunction that causes a boron dilution event is discussed in Section 5.1.19 of Reference 4 and is evaluated by the NRC staff in Section 3.4.2.16 of this report. In the analysis, operator action was credited to mitigate the event by reducing charging flow or restoring letdown flow. Operator action was assumed to occur at 20 minutes after the Pressurizer high level alarm actuates. The assumed operator action delay time is consistent with the current UFSAR, Section 15.5.2 and, therefore, is acceptable. The assumed single failure was the complete closure of the letdown flow control valve that occurred concurrently with the start of the second charging pump and was consistent with the assumptions used in the AOR. The results of the analysis demonstrated that the pressurizer volume does not become water solid prior to 20 minutes after the pressurizer high level alarm is actuated, assuring that no water is discharged through the pressurizer safety valves.

During the CVCS malfunction, the changes in core power, RCS temperatures and RCS mass flow are small. With respect to peak RCS and main steam system pressures, the event is bounded by the LOCV event described in Section 5.1.10 of Reference 4, which was analyzed with assumptions that were made to conservatively calculate the RCS and main steam system pressures (see Section 3.4.2.7 of this safety evaluation). With respect to fuel damage because of low DNBR, the event is bounded by the CEA bank withdrawal-at-power described in Section 5.1.16 of Reference 4 and evaluated in Section 3.4.2.13 of this safety evaluation.

Therefore, the NRC staff concludes that the analysis meets the acceptance criteria of SRP Section 15.5.2 with respect to the acceptable limits of the maximum pressurizer water level, peak RCS and main steam system pressures and SAL DNBRs, and is acceptable.

3.4.2.19 Pressurizer Pressure Decrease - Inadvertent Opening of the Pressurizer Relief Valves

An accidental depressurization of the RCS may occur as a result of an inadvertent opening of both of the pressurizer PORVs, an inadvertent opening of a single pressurizer safety valve, or a malfunction of the pressurizer spray system. This event results in a decrease in the RCS pressure. The depressurization of the RCS can cause the fuel to approach to the SAL DNBRs. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following the reactor trip initiated by the TM/LP trip signal.

In the case of St. Lucie Unit 2, the pressurizer safety valve is sized to discharge approximately half the steam flow rate of a PORV, and the pressurizer spray system cannot depressurize the RCS at the rate of two open PORVs. The licensee analyzed the event of opening both PORVs, which is the limiting depressurization case, resulting in the lowest value of DNBR. Section 5.1.22 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of this event.

The licensee used acceptable computer codes to analyze this event. RETRAN was used to calculate the RCS power, pressure and temperature and VIPRE was used to calculate the DNBRs. In the analysis, the initial reactor power and RCS temperature were assumed to be at their nominal values corresponding to 89-percent power, the initial RCS flow rate was assumed at a value consistent with the minimum measured flow rate, and the initial RCS pressure was assumed at a value consistent with the minimum value permitted by the plant's TSs. Uncertainties in initial conditions were statistically included in the calculation of the DNBR limit as described in WCAP-11397-P-A. The results of the analysis showed that, during the transient, nuclear power remained relatively constant while pressurizer pressure decreased from the initial value until a reactor trip occurred at the lower limit of the TM/LP trip. The calculated DNBRs showed that the minimum DNBR is above the SAL DNBRs, thus assuring that no fuel damage will occur during this event.

Based on its review, as discussed above, the NRC staff finds that acceptable methods and adequate assumptions are used in the analysis, and the results of the analysis show that no calculated DNBR values fall below the safety DNBR limit. Therefore, the NRC staff concludes that the analysis meets the acceptance criterion of SRP Section 15.6.1 with respect to the SAL DNBRs, and is acceptable.

3.4.2.20 Primary Line Break Outside Containment

Section 5.1.23 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of primary line breaks outside containment. A small primary line break outside containment may result from a break in a letdown line, instrumentation line or sample line. The case presented in Section 15.6.2 of the UFSAR is the double-ended break of the letdown line outside containment upstream of the outside containment isolation valve, because it is the largest line break and results in the largest release of the reactor coolant to the environment. In support of the proposed operation with the SGTP limit increased to 42 percent, the licensee evaluated the key inputs and assumptions of the current AOR in USFAR Section 15.6.2 (Ref. 21) and indicated that the AOR case remains the bounding case.

During the course of the review, the NRC staff requested the licensee to revise Section 5.1.23 of Reference 4 to reflect the proposed operating conditions of a maximum power of 89-percent RTP with a minimum RCS flow of 300,000 gpm and an SGTP level of 42 percent. Specifically, the NRC staff requested the licensee to justify that the AOR case is still a limiting case with consideration of the effects of changes in initial RCS temperature, pressurizer conditions, and operating power level corresponding to the 42-percent SGTP limit conditions. The licensee indicated in its response to RAI-20 (Ref. 2) that the leak rate from the letdown line break is determined by the upstream (cold-leg) temperature and pressure, and will not be adversely affected by changes in RCS flow or SGTP. As shown in UFSAR Figure 15.6.2-3, the RCS temperature remains constant prior to a reactor trip and the range of initial cold-leg temperatures (up to 549 ^{0}F) in the AOR is not affected by the increase in SGTP (547.1 ^{o}F). Further, the initial pressurizer pressure remains unchanged at 2250 psia for the 42-percent SGTP case. As shown in UFSAR 15.6.2-4, the RCS pressure decreases prior to a reactor trip on low pressurizer pressure, with the extent of RCS pressure decrease determined by the pressurizer conditions, reactor power, and the decrease in reactor coolant volume caused by the break. The pressurizer conditions (including the range of initial pressure and liquid level, charging flow and heat capacity) are not changed by the increase in SGTP. Also, the reduction in operating power would result in beneficial effects. Therefore, the pressure transient before the reactor trip shown in USFAR 15.6.2-4 remains valid as a limiting case for the 42-percent SGTP case, and the pre-trip leakage will remain bounding.

The AOR described in UFSAR Section 15.6.2 assumed that, following a reactor trip, the leak rate from the letdown line was 45 lbm/sec for 10 minutes after the safety injection actuation signal was initiated on low pressurizer pressure. The safety injection actuation signal also initiated closure of the letdown line isolation valves. The leak rate was based (Ref. 6) on analyses performed with the CESEC code that showed that the letdown flow decreased from about 49 lbm/sec at the time of the reactor trip caused by the low pressurizer pressure to less than 41 lbm/sec at about 82 seconds after reactor trip, which was just before closure of the letdown line isolation valves. Therefore, the letdown leak rate of 45 lbm/sec for 10 minutes assumed in the analysis results in the release of a greater volume of RCS inventory with an associated higher dose, and is conservative. In addition, the impact of initial RCS flow and SGTP on assumed post-trip leak flow rate will be small because cold-leg temperature decreases and equilibrates to a value determined by the MSSV setpoint, which remains unchanged for a case with an increase in SGTP. The post-trip pressure decrease is caused by coolant contraction as the RCS average temperature decreases to a value determined by the MSSV setpoint. For a given temperature in the SG secondary side, a higher RCS average temperature will result in a greater primary-to-secondary heat transfer capability from the RCS, while a smaller SG heat transfer area will decrease heat transfer capability. Therefore, the amount of depressurization resulting from the coolant contraction will be slightly greater when the initial average temperature is higher for cases with a reduced RCS flow, and will decrease slightly when the available heat transfer area becomes smaller because of a higher level of SGTP. The effects of both a reduced RCS flow and a decreased SG heat transfer area on depressurization are small, and offsetting to each other. Also, the reduction in operating power to 89 percent will reduce the leakage rate and provide additional margin to the results of the AOR case.

Based on the review discussed above, the NRC staff agreed with the licensee that an increase in SGTP level to 42 percent with a decrease in minimum RCS flow from 335,000 gpm to 300,000 gpm has a negligible effect on this event. A reduction in power level from 100 percent to 89 percent RTP provides additional margin to the AOR results. Therefore, the NRC staff concludes that the AOR documented in UFSAR 15.6.2 remains bounding and acceptable.

3.4.2.21 Steam Generator Tube Rupture with a Concurrent Loss of Offsite Power

Section 5.1.24 of the St. Lucie Unit 2 licensing report (Ref. 4) describes the analysis of a SG tube rupture (SGTR) event. An SGTR event causes direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and SG safety or atmospheric relief valves. Reactor protection and engineered safety features are actuated to mitigate the accident. The NRC staff's review covers postulated initial core and plant conditions, method of thermal and hydraulic analysis, sequence of events assuming a loss of offsite power, assumed reactions of reactor system components, functional and operational characteristics of the RPS, and the results of the accident analysis. The NRC staff's review for the SGTR analysis discussed in this section is focused on calculations of the mass releases that are used for calculating radiological consequences, and follows the acceptance criteria specified SRP Section 15.6.3.

The licensee performed an SGTR thermal-hydraulic analysis for determining steam releases used to calculate the radiological consequences. The analysis was performed using methodology consistent with the current AOR (i.e., the CESEC code). The analysis assumed a core power of 89-percent RTP with 2 percent uncertainty, 42-percent SGTP in each SG, and a SG tube break area of 0.336 in^2, which is consistent with the AOR. The analysis credited the TM/LP low pressurizer pressure trip signal to trip the reactor and to provide protection against undesirable conditions. Consistent with the AOR, following an SGTR event, a LOOP was assumed to occur concurrent with the reactor trip. Following the reactor trip and turbine trip, steam would release through the MSSVs until the operator isolated the affected SG. With the availability of stand-by power, emergency feedwater was assumed to initiate on a low SG water level signal. Consistent with the current analysis, the licensee assumed that at 30 minutes after event initiation the operators isolated the affected and initiated plant cooldown using the unaffected SG atmospheric dump valves. The resulting steam releases were then used to calculate the radiological consequences of the SGTR.

The results of the analysis showed that the RCS primary and secondary pressures do not exceed 110 percent of the design pressures, and the TM/LP trip assures that the SAL DNBRs are met. The NRC staff also found that the analysis of the SGTR adequately accounted for the proposed SGTP level of 42 percent with a power level of 89-percent of RTP and was performed using approved computer codes. Further, the assumptions used in this analysis were consistent with the AOR in maximizing the primary-to-secondary leakage and mass releases to the atmosphere. Therefore, the NRC staff concludes that the SGTR analysis meets the acceptance criteria of SRP 15.6.3 with respect to DNBR limit, pressure limits, and the guidance for calculating the maximum mass release, and is acceptable.

3.4.3 Loss-of-Coolant Accidents Resulting from Postulated Reactor Coolant Piping Failure

In the review of the spectrum of postulated LOCAs that was provided by the licensee to support operation with up to 42-percent SGTP, the NRC staff utilized the guidance contained in Section 15.6.5 of the SRP and the requirements contained in 10 CFR 50.46. The licensee divided the LOCA evaluations into three sections: large-break LOCA, small-break LOCA, and post-LOCA long term cooling. Each section uses a different methodology and was, therefore, reviewed separately by the NRC staff.

3.4.3.1 Large-Break LOCA

These evaluations involve the phenomena that would occur following the severance of a large coolant pipe. They include the initial voiding of the core from the high pressure coolant loss, which is called the blowdown period, and the postblowdown period during which the voided core is heated until it is refilled by the ECCS, which is called the reflood period. A large break at the discharge of a RCP would produce the most disadvantageous conditions for large-break LOCA since a portion of the injected ECC water would be lost from the break without reaching the core. At this location an early flow reversal would occur in the core causing degradation in core heat transfer and a sharp rise in fuel cladding temperature. The cladding temperature would reach a peak value and then be reduced as core flow is established in the reverse direction. This is called the blowdown peak. As the core is eventually voided, the cladding temperature will begin to rise again. The cladding will reach a second peak temperature value just before being recovered with water injected by ECCS that will flood the core from the bottom. This is called the reflood peak.

For operation with up to 42-percent SGTP, the most significant parameters that will affect the consequences of a large-break LOCA are the initial core power and the increase in loop flow resistance as a result of the plugged SG tubes. The blowdown peak would be most affected by initial core power. For the initially lower core operating power of 89 percent, the core would contain less stored energy so that less cladding heatup would be produced by the early flow reversal. The reflood peak would be affected by the increase in loop flow resistance as well as by the initial core power. This is because steam generated by the core must traverse the SGs to exit the reactor system for a large cold leg break. The increase in loop flow resistance from SG tube plugging would retard the flow of steam that must exit the core and thereby retard the rate at which the core is reflooded.

The licensee reanalyzed the consequences of a large break LOCA using the same methodology that the NRC staff had previously approved for operation with up to 30-percent SGTP (Ref. 6). The CEFLASH-4A computer code was used to calculate reactor coolant pressures, temperatures, and flow rates during the blowdown period. The COMPERC-II computer code was used to calculate these quantities during the reflood period. The heatup of the hottest fuel rod was calculated using the STRIKEN-II computer code and the core-wide cladding oxidation was calculated using the COMZIRC computer code.

The licensee evaluated the effect of a single failure in the safety systems, including emergency diesel generator failure and the failure of a low pressure safety injection system. The case with all safety systems operating was determined to be the most limiting condition for the reactor core because the operation of all containment sprays and fan coolers, as well as the effect of maximum ECCS water spillage from the RCS, would act to lower containment and reactor system pressure. At a lower containment pressure, the steam exiting the core would require more volume that would increase the flow resistance for the steam to reach the break. This effect will slow the entry of ECCS water reflooding the core. The licensee performed analyses for a spectrum of large break sizes. The break size producing the most limiting core conditions was found to be a double-ended guillotine break at the discharge of a RCP with a discharge coefficient of 0.4. The peak cladding temperature, maximum cladding oxidation in the hot fuel rod, and maximum core-wide cladding oxidation were determined to be less than the acceptance criteria limits of 10 CFR 50.46. These results were, therefore, acceptable to the NRC staff. The peak cladding temperature for the most severe large break size at 89 percent of full power and 42-percent SGTP was found to be 18 ^{o}F less than that for the most severe break size for the present analyzed condition with 30-percent SGTP and at full power.

3.4.3.2 Small-Break LOCA

If a break were sufficiently small, the reactor system pressure would not decrease enough for low pressure injection to occur and safety injection tank flow would be reduced or prevented. The high pressure safety injection (HPSI) system would be the primary means of emergency core coolant delivery to the reactor core. For operation with up to 42-percent SGTP, the most significant parameter that will affect the consequences of a small-break LOCA would be the core power, which was reduced to 89 percent of the current full power limit. The reduction in SG heat transfer area might have some effect on the calculated result since the SGs are needed to remove decay heat and reduce reactor system pressure for a small-break LOCA. However, even with an effective heat transfer area reduction of 42 percent, the SGs would be expected to have adequate heat transfer area to remove decay heat.

As was done for the large-break LOCA, the licensee reanalyzed the consequences of a small-break LOCA using the same methodology that the NRC staff had previously approved for operation with up to 30-percent SGTP (Ref. 6). The CEFLASH-4A computer code was used to calculate reactor coolant pressures, temperatures and flow rates during the blowdown period. The heatup of the hottest fuel rod was calculated using the STRIKEN-II computer code during the initial period of forced convection heat transfer and by the PARCH computer code during the subsequent period of pool boiling heat transfer. The safety injection tanks were assumed not to inject even when the RCS pressure dropped sufficiently. Failure of an emergency diesel generator was determined to be the most limiting single failure condition for small-break LOCAs since this failure would cause loss of one HPSI pump.

The licensee performed analyses for a spectrum of small-break sizes. The break size producing the most limiting core conditions was found to be a RCP discharge break of 0.045 ft^2. The peak cladding temperature of the hottest rod with 42-percent SGTP and an initial power level of 89 percent was calculated to be 466 °F less than was the case with 30-percent SGTP and an initial power of 100 percent. The peak cladding temperature, maximum cladding oxidation in the hot fuel rod, and maximum core wide cladding oxidation continue to be less then the acceptance criteria limits of 10 CFR 50.46. These results were, therefore, acceptable to the NRC staff.

3.4.3.3 Post-LOCA Long-Term-Cooling

The licensee performed two evaluations of LTC to assure the adequacy of decay heat removal for both large and small break sizes and to ensure that the boric acid contained in the reactor coolant and the ECCS water did not concentrate in the core to above its solubility limit. Boric acid, if sufficiently concentrated by core boiling, has the potential to cause core channel blockage.

For both LTC analyses, the licensee references topical report CENPD-254-P-A (Ref. 22) that was approved by the NRC staff. This is the same approach used by the licensee for the evaluations of the previously NRC-approved 30-percent SGTP limit with the exception of modifications to the boric acid concentration evaluation. The modifications were the result of an NRC letter (Ref. 23) that suspended staff approval of CENPD-254-P-A and required a more conservative consideration of the reactor vessel liquid water mass.

For small breaks, the reactor system can be refilled and the reactor cooled by the shutdown cooling system (SCS). With the reactor system filled and circulation through the core provided by the SCS, boric acid concentration is not a concern. Following a large cold-leg LOCA during the LTC period, the core will be cooled by boiling. Steam from the boiling process will leave the core, travel through the SGs and exit at the break. ECCS flow reaching the reactor vessel downcomer from the cold legs will replenish the water lost from the core by the boiling process and any excess ECCS flow will spill into the containment. Continued boiling in the core will concentrate the boric acid that is brought in by the ECCS water and is left behind by the departing steam. An important parameter in the analysis of boric acid concentration is the mass of water in the reactor vessel that is available for mixing with and diluting the boric acid in the core. As a result of the NRC staff letter (Ref. 23) and additional discussions with the NRC staff, the license now uses a mixing volume that considers the two-phase conditions of the core and upper plenum and takes credit for only a portion of the lower plenum volume. In response to RAI-14 (Ref. 2) the licensee provided information on its determination of the mixing volume, which enabled the NRC staff to perform an independent analysis of boron concentration within the reactor core following a large break LOCA. The licensee calculated the water mass in the core using an NRC-approved void fraction model (Ref. 24) that accounts for the increase in steam separation velocity at low pressure The mass of water in the upper plenum was conservatively calculated assuming that the two-phase level extends only to the bottom of the hot legs. A correction was applied to account for the increased cross-sectional area of the upper plenum as compared to the core.

Little boiling will occur in the lower plenum of the reactor vessel, however, all the water in the lower plenum might not be available to mix with the boric acid in the core. The licensee cited proprietary data taken at the BACCHUS facility that was made available to the NRC staff

(Ref. 26). The BACCHUS data showed that, for the simulated reactor vessel, little mixing would occur until the density of the boric acid in the core reached a critical value. Above the critical value, considerable mixing would occur. The critical value of boric acid density is considerably less than that for which boric acid precipitation would occur from boiling in the core. The data indicates that the assumption of one-half the water mass in the lower plenum available for mixing is conservative. This was the value used by the licensee.

In order to provide an independent assessment of the reactor vessel mass available to mix with the boric acid being concentrated by boiling in the core, the NRC staff performed an analysis of LTC following a large-break LOCA using the RELAP5 computer code. RELAP5 contains models that are able to predict steam and water fractions within boiling systems and that have been benchmarked against experimental data. The licensee's core and upper plenum mass predictions were found to be conservative when compared to the predictions of RELAP5. Furthermore, RELAP5 predicted a circulation path of down-flow through the core bypass region between the core barrel and core shroud. The mass of water within the core bypass region was conservatively omitted from the licensee's calculations.

Because of the nodal nature of the RELAP5 model, no information regarding mixing in the lower plenum could be obtained. Instead the NRC staff performed an analysis of lower plenum mixing using the computational fluid dynamics computer code FLUENT with inputs for core boil-off and core-bypass flow provided by the RELAP5 analysis. FLUENT is capable of following the fluid eddy currents produced by density differences in 2 and 3 dimensions. The FLUENT analysis performed by the NRC staff did not include the smaller eddy currents that arise as an effect of turbulence and would produce additional mixing. The code is, therefore, capable of conservatively predicting mixing of the water coming into the bottom of the lower plenum from the downcomer with the more concentrated and more dense boric acid solution in the core and core bypass region. The NRC staff's FLUENT analysis confirmed that the licensee's use of one-half of the lower plenum water mass for boric acid mixing was conservative.

As a further check of the licensee's calculations, the NRC staff performed an evaluation of the reactor core boric acid inventory using the values assumed by the licensee for incoming ECCS flows and boric acid concentrations entering the reactor vessel. The NRC staff's calculations agreed with those done by the licensee.

The licensee provided analyses showing that, if hot-leg injection is initiated at 6 hours after a LOCA, reverse flow will occur in the core and the boric acid concentration will be diluted. In order for water injected in the hot legs to reach the core, it would have to flow against the flow of steam generated in the core and traveling to the break. Using an approved methodology, the licensee calculated the conditions necessary for the exiting steam to entrain the hot-leg injection and demonstrated that no entrainment of the hot-leg injection would occur.

The licensee's decay heat removal analysis uses the NATFLOW, CELDA, and CEPAC computer codes to demonstrate that the core remains covered with two-phase liquid in the long term, thereby assuring that, for all break sizes, the core temperature is maintained at an acceptably low value. For breaks that are sufficiently large, the reactor system will depressurize sufficiently so that the steam generated in the core can be removed by the break and high pressure injection can replenish the coolant that is boiled in the core. For small breaks, the reactor system can be depressurized by pressurizer spray and by heat removal in the SGs so that high pressure injection can refill the reactor system. With the reactor system filled, the SCS can be activated for continued long term heat removal.

Analyses by the licensee, using approved methodology, demonstrated that the reactor system can be refilled and placed on the SCS within 16 hours for break sizes of 0.036 ft^2 and smaller. The analyses also show that for break sizes of 0.005 ft^2 and larger, HPSI can maintain core cooling with the steam generated in the core removed by the break. Since a considerable overlap exists in calculated break sizes for which the core will be adequately cooled by either method, the NRC staff concluded that the provisions for decay heat removal were adequate. During the post-accident recovery, the plant operating staff would use a pressure criterion calculated by the approved methodology to decide which cooling method to use at the end of 16 hours. At the request of the NRC staff, the licensee provided justification that a sufficient source of safety-related auxiliary feedwater will be available to support the 16-hour decision time.

At another CE-designed facility, it was discovered that the containment pressure during the recovery from a small-break LOCA might be lower than originally assumed. At the lower containment pressure, when the HPSI pumps switch suction from the refueling water tank (RWT) to the containment sump, the HPSI pumps might continue to take water from the RWT as the valves are realigned. As a result, the level in the RWT might drop sufficiently for air to be ingested into the HPSI pumps from vortexing. The NRC staff requested that the licensee provide justification that, following a small-break LOCA at St. Lucie Unit 2, air will not be ingested into the HPSI pumps during switch over of suction to the containment sump. The licensee responded that at St. Lucie Unit 2, valve operations isolating the RWT and opening the lines to the containment sump are automatically actuated. Furthermore, the valves isolating the RWT will begin to close while there is sufficient water within the RWT to allow suction to continue from the RWT until the isolation valves are fully closed without air ingestion occurring. Therefore, the automated valve sequencing of the switchover design precludes ingestion of air into the HPSI pump suction. The NRC staff finds this acceptable.

3.5 Changes to TSs

3.5.1 TS Table 3.2-2, DNB Parameters

The current TS 3.2.5, “Power Distribution Limits, DNB Parameters, Limiting Conditions for Operation” establishes the following Limiting Condition for Operation for RCS Flow in Table 3.2-2, “DNB Margin Limits”

Reactor Coolant Flow Rate	≥ 335,000 gpm and ≥ the limit specified in the COLR Table 3.2-2

In Ref. 1, the licensee proposed to add a footnote applicable to the parameter: “Reactor Coolant Flow Rate” listed in TS Table 3.2-2 as follows:

> “Commencing with the startup for Cycle 16 and until the Combustion Engineering Model 3410 Steam Generators are replaced, if the reactor coolant flow rate is less than 335,000 gpm but greater than or equal to 300,000 gpm, then the maximum reactor THERMAL POWER shall not exceed 89 percent of the RATED THERMAL POWER of 2700 MWt.”

The NRC staff found that the proposed footnote was not acceptable, because it would allow operation at 100 percent RTP with greater than 30-percent SGTP as long as RCS flow was greater than 335,000 gpm, which is not consistent with the acceptable safety analyses (discussed in Section 3.4 of this evaluation). Also, in subsequent discussions between the NRC staff and the licensee, it was agreed that the Table 3.2-2 footnote should focus on RCS flow rate and that restrictions on other parameters should be covered elsewhere. In Ref. 3, the licensee proposed the following license conditions to be added to Paragraph 3.A, "Maximum Power Level," of the St. Lucie Unit 2 Renewed Operating License:

> Commencing with the startup for Cycle 16 and until the Combustion Engineering Model 3410 Steam Generators are replaced, the maximum reactor core power shall not exceed 89 percent of 2700 megawatts (thermal) if:
>
> a. The Reactor Coolant System Flow Rate is less than 335,000 gpm but greater than or equal to 300,000 gpm, or
>
> b. The Reactor Coolant System Flow Rate is greater than or equal to 300,000 gpm AND the percentage of steam generator tubes plugged is greater than 30 percent (2520 tubes/SG) but less than or equal to 42 percent (3532 tubes/SG).
>
> This restriction in maximum reactor core power is based on analyses provided by FPL in submittals dated October 21, 2005 and February 28, 2006, and approved by the NRC in Amendment No. 145, which limits the percent of steam generator tubes plugged to a maximum of 42 percent (3532 tubes/SG) in either steam generator and limits the plugging asymmetry between steam generators to a maximum of 600 tubes .

The licensee also proposed to revise the TS Table 3.2-2 footnote as follows:

> Commencing with the startup for Cycle 16 and until the Combustion Engineering Model 3410 Steam Generators are replaced, Reactor Coolant Flow Rate will also be limited in accordance with Renewed Operating License Paragraph 3.A.

The NRC staff concludes that the proposed revision to Paragraph 3.A of the St. Lucie Unit 2 Renewed Operating License provides restrictions on RTP, SGTP and RCS flow that are consistent with the analyses provided for the proposed amendment and is, therefore, acceptable. Also, the proposed footnote to TS Table 3.2-2 is acceptable because it properly focuses on RCS flow and the link to the license condition provides additional restrictions on RCS flow that are consistent with the analyses provided for the proposed amendment.

3.5.2 TS Surveillance Requirement (SR) 4.2.5.2

The TS SR 4.2.5.2 requires that the RCS total flow rate be determined to be within its limits by measurement at least once per 18 months. Its associated footnote further specifies that the RCS flow measurement is not required to be performed until thermal power is greater than or equal to 90 percent of RTP. If the maximum power level is restricted to 89 percent of RTP in accordance with the proposed amendment, flow measurement at or above 90 percent of RTP is not feasible. The licensee proposed to change the SR to require the total flow rate to be determined greater than or equal to 80 percent of RTP. The NRC staff finds that the proposed change meets the intent of the TS SR and is a necessary conforming change, since power could be limited to 89 percent of RTP by the proposed amendment. Therefore, the NRC staff concludes that TS change is acceptable.

3.6 Conclusions

As a result of its review discussed above, the NRC staff found that (1) the supporting analyses used previously NRC-approved methodologies and computer codes with adequate values for key plant parameters, and (2) the results of the safety analyses meets applicable acceptance criteria specified in Chapters 4 and15 of the SRP for analyses of fuel design physics, and non-LOCA and LOCA transients. Therefore, the NRC staff concluded that the analyses were acceptable for use in support of the licensee's request to operate the St. Lucie Unit 2 plant with 42-percent SGTP in each SG at a maximum power of 89 percent of RTP.

The NRC staff also concluded that the proposed TS changes and the license conditions discussed in Section 3.5 were acceptable because they reflect the acceptable safety analyses discussed in Section 3.4.

4.0 RADIOLOGICAL DOSE CONSEQUENCES

The NRC staff reviewed the regulatory and technical analyses, as related to the radiological consequences of design basis accidents, performed by FPL in support of the proposed license amendment. Information regarding these analyses was provided in Section 4, and Attachment 6, Sections 5.1.24 and 5.4,of Reference 1, and in a supplementary letter (Ref. 2). The NRC staff reviewed the assumptions, inputs, and methods used by FPL to assess the impacts of the proposed license amendment and based its findings on the descriptions of the licensee's analyses and other supporting information provided by the licensee.

FPL completed non-LOCA safety analyses supporting operation at 89 percent power, with up to 42-percent SGTP. The licensee evaluated the impact on the design basis accident (DBA) dose analyses of operation of St. Lucie Unit 2 with up to 42-percent SGTP, by comparing the key inputs from the revised safety analyses to those used in the existing radiological consequences AOR. In addition, FPL recalculated the radiological consequences of the SGTR accident for the proposed changes and 42-percent SGTP.

4.1 Impact on Inputs to Non-LOCA DBA Dose Analyses

The majority of the input parameters for the radiological consequences AOR are not impacted by operation at 89 percent power with up to 42-percent SGTP because they are governed by regulation, TSs that are not changed, or are in the current licensing basis for St. Lucie Unit 2. The impact of the proposed changes on input to the radiological consequences analyses are discussed below.

4.1.1 Core Power

The licensee stated that the proposed decrease in core power to 89 percent will reduce the inventory of fission products in the fuel, and subsequently the decay heat, by about 11 percent. Because of the decrease in decay heat, the steam releases are also reduced. The licensee stated, and the staff agrees, that both of these effects would reduce the calculated dose. The dose analysis inputs for core isotopic inventory and non-LOCA steaming due to decay heat, would be less for operation at 89 percent power than in the existing AOR. FPL has not proposed to change the TS limit of primary coolant or secondary coolant activity, therefore, the proposed license amendment does not impact the isotopes or activities assumed in the RCS fluid. Based on the above, the staff agrees that the St. Lucie Unit 2 radiological consequences AOR inputs are bounding for the decrease in core power and the licensee would not be required to reanalyze the DBA radiological consequences for the reduction in core power.

4.1.2 RCS Flow and Temperature

The staff agrees with the licensee that decreasing the RCS flow rate from 335,000 gpm to 300,000 gpm in the RCS will not have any direct impact on the radiological consequences. However, the licensee stated that the reduction in flow will reduce the SG pressure. This is discussed further in Section 4.1.3.

Decreasing cold-leg temperature from 549.0 ^{o}F to the range of 546.0 to 547.1 ^{o}F will reduce the fraction of leaked fluid that is flashed to steam. The flashing fraction is reduced because, since the temperature of the leaked RCS fluid is decreased for the proposed changes while the pressure is assumed to stay the same, the enthalpy of the fluid is also decreased. Therefore, the existing AOR flashing fraction assumptions remain bounding for the reduction in cold-leg temperature, and the staff agrees that the licensee would not be required to reanalyze the DBA radiological consequences analysis for the reduction in cold-leg temperature.

4.1.3 Steam Generator Pressure

The licensee stated that decreasing the minimum SG pressure from 810 psia to 724 psia will increase the heat of vaporization of the SG water and also increase the density of the water in the SG at saturated conditions. These effects will reduce the amount of steaming needed to remove heat from the RCS and also reduce the activity concentration in the SG. However, reducing SG pressure would increase the flashing fraction of the primary-to-secondary leakage, in opposition to the reduction in the flashing fraction due to the decrease in RCS temperature. This increase in the flashing fraction would increase the calculated dose for releases from the SGs. The licensee stated that the overall impact on the dose analyses of the decrease in SG pressure, and the resulting increase in the flashing fraction (and subsequent fission product release), is offset by the decrease in fission product release from the reduction in core power, reduction in flashing fraction due to the RCS temperature reduction, and reduction in steaming and activity concentration due to the SG fluid density reduction. The staff finds the licensee’s conclusion acceptable.

4.1.4 Conclusion for AOR Dose Analyses Other Than SGTR

FPL evaluated the impact on the AOR dose analyses of operation at 89-percent power with up to 42-percent SGTP for the following events:

- Pre-trip steam line break (inside and outside containment)
- Post-trip steam line break (inside and outside containment)
- Feedwater line break
- Control element assembly ejection
- Inadvertent opening of a MSSV
- Locked rotor/sheared shaft
- Letdown (primary) line break
- LOCA
- Fuel handling accidents and the waste gas decay tank rupture

For these accidents and events, the licensee considered the changes to the RCS liquid mass and activity concentration, steam flow out of the SG after the event, changes in the fission product release from failed fuel, and changes to primary-to-secondary leakage and flashing fraction. FPL's evaluations showed the majority of the parameters used in radiological consequences analyses do not change as a result of the reduction in core power level or increase in SGTP. The licensee found that the only effect that adversely impacts the radiological consequences calculations was an increase in fluid flashing fraction due to reduced SG pressure. As discussed above, the licensee determined that the impact of the increased flashing fraction due to reduced SG pressure would be more than offset by the other beneficial impacts from the decrease in core power, decrease in RCS temperature and reduction in steaming and RCS fluid density from the decrease in SG pressure. The licensee further determined that the existing radiological consequences AOR remain bounding, and that 10 CFR Part 100 and GDC 19 continue to be met for the proposed changes. The staff finds the licensee's evaluations to be reasonable and agrees with the licensee's determination that the referenced dose AOR for DBAs other than the SGTR remain bounding and does not need to be revised for the proposed changes to allow operation at 89 percent power with up to 42-percent SGTP at St. Lucie Unit 2.

4.2 <u>SGTR Revised Analysis</u>

FPL evaluated the SGTR with a LOOP accident to account for the conditions with up to 42-percent SGTP and 89-percent core power. The licensee used the existing radiological consequences AOR as the basis for the revised evaluation. The licensee's analysis assumptions and inputs are listed in Table 5.1.24-1 of Attachment 8 to Reference 1. All analysis assumptions and inputs are the same as those previously reviewed and approved for St. Lucie Unit 2 operation with up to 30-percent SGTP in Amendment No. 138 (Ref. 6), with the exception of the following assumption changes related to proposed changes in SGTP level and core power.

1. The timing of the SGTR sequence of events is different, although the values were calculated using the same methodology as previously approved in Amendment No. 138.

2. The steam releases from the condenser, through the MSSVs, and from SG atmospheric dump valves until 1800 seconds into the accident are larger.

3. The primary-to-secondary leakage to the affected SG until 1800 seconds is larger.

4. The break flow flashing fraction is based on thermal hydraulic data for the 42-percent SGTP conditions and is larger prior to the reactor trip, but slightly lower after the trip.

The values were calculated using the methodology previously used by the licensee in support of the analyses for 30-percent SGTP, as approved in Amendment No. 138.

All other assumptions and inputs are the same as previously approved by the staff in Amendment No. 138, and would not be impacted by the proposed changes for 42-percent SGTP and 89-percent core power. The licensee did not change the activity concentration per unit mass of RCS fluid because there was no proposed change to the RCS activity TS limit. In accordance with RG 1.183 guidance, FPL calculated the doses for two separate iodine activity cases - a preaccident iodine spike and a concurrent iodine spike. The analysis calculational methodology is the same as previously approved, and continues to follow the guidance given in RG 1.183 for SGTR dose analysis with an AST. The dose results for FPL's revised analysis of the radiological consequences of the SGTR with LOOP for 42-percent SGTP and 89-percent core power are increased slightly over the AOR values. The licensee's results for the total effective dose equivalent (TEDE) at the exclusion area boundary (EAB), low population zone (LPZ) and in the control room, and the applicable regulatory dose acceptance criteria are given in Table 1 of this safety evaluation (Attachment). The licensee's estimated doses remain within the RG 1.183 regulatory dose acceptance criteria, 10 CFR 50.67 reference values for both offsite and control room doses, and GDC 19 for the control room.

4.3 Conclusion

The NRC staff finds that FPL used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified in Section 2.2 above. The NRC staff compared the doses estimated by FPL to the applicable criteria identified in Section 2.2 and finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and control room doses will continue to comply with these criteria. Therefore, the proposed changes to TS to allow up to 42 percent SG tube plugging is acceptable with regard to the radiological consequences of postulated DBAs.

5.0 STEAM GENERATOR TUBE INTEGRITY

5.1 Technical Evaluation

The change in operating parameters as a result of the 42-percent SGTP proposal resulted in the licensee reevaluating portions of the original qualification of the Leak Limiting Alloy 800 SG tube sleeves and the adequacy of the tube repair limit (i.e., the 40-percent depth based tube repair limit), given the higher differential pressures expected across the SG tubes with 42-percent SGTP.

The NRC staff approved the use of Westinghouse Leak Limiting Alloy 800 sleeves at St. Lucie Unit 2 in Amendment No. 144 (Ref. 7), based on analyses provided in Westinghouse Topical Report WCAP-15918-P, Revision 2, "Steam Generator Tube Repair for Combustion Engineering and Westinghouse Designed Plants with 3/4-inch Inconel 600 Tubes using Leak Limiting Alloy 800 Sleeves," dated July 2004 (Ref. 29). The licensee assessed the following areas with respect to the use of Leak Limiting Alloy 800 sleeves under the 42-percent SGTP proposal: minimum wall thickness, maximum primary-to-secondary differential pressure, maximum axial load from differential thermal expansion on the sleeve-tube assembly, and secondary flow velocities. With the exception of the maximum primary-to-secondary differential pressure, the analysis provided in WCAP-15918-P, Revision 2, remains bounding with

42-percent SGTP. The implications of this increased maximum primary-to-secondary differential pressure on both the tube and the sleeve are discussed below.

With 42-percent SGTP, the minimum operating SG pressure will be 724 psia. This value is less than the minimum operating SG pressure of 790 psia assumed in WCAP-15918-P for the Leak Limiting Alloy 800 sleeves. As a result, the differential operating pressure with 42-percent SGTP is 1526 psi, whereas the differential operating pressure assumed in WCAP-15918-P is 1460 psi. Due to this change in differential pressure, the allowable sleeve wall degradation will be approximately 3 percent lower for operation with 42-percent SGTP than that described in WCAP-15918-P.

Although the amount of sleeve degradation that can be tolerated with 42-percent SGTP is less than what was calculated in WCAP-15918-P, the change is inconsequential given that the licensee is required to plug any tube upon detection of degradation in the sleeve or pressure boundary portion of the original tube wall in the sleeve/tube assembly (i.e., the sleeve-to-tube joint). Given the licensee's current requirement to "plug on detection," the change in the allowable sleeve wall degradation has no effect on the plugging criteria for the sleeves contained in the TSs. In addition, given the current inspection and repair requirements pertaining to the sleeves (e.g., the licensee is required to inspect the parent tube at the location where any sleeve joint is to be established) and the licensee's plan to replace the SGs after one cycle of additional operation, the likelihood of growing a flaw that could challenge tube integrity over the course of one cycle is limited. Therefore, the staff concludes that the increase in the maximum primary-to-secondary differential pressure due to the 42-percent SGTP operation is acceptable with respect to the use of Leak Limiting Alloy 800 sleeves.

The licensee also evaluated the effect of the increased differential pressure on the SG tube repair limit in the St. Lucie Unit 2 TSs (i.e., the repair limit associated with the nonsleeved regions of the tube). The licensee's April 24, 2006 letter (Ref. 30) provides the results of the licensee's analysis regarding the adequacy of the tube repair limit, given the higher differential pressure across the steam generator tubes with 42-percent SGTP. This analysis was performed in accordance with RG 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." This analysis indicated that a tube with 60-percent wall thinning will still meet the criteria in RG 1.121, and led the licensee to conclude that the 40-percent depth based tube repair limit remained acceptable with 42-percent SGTP. The staff concludes that the change in differential pressure with 42-percent SGTP should not have a significant effect on the tube repair limit and concludes that the 40-percent depth based tube repair limit remains acceptable for operation with 42-percent SGTP.

5.2 Change to TSs

The licensee proposed to revise TS SR 4.4.5.4.a.10 to add "(with the range of conditions as revised in Appendix A of the WCAP-16489-NP, Revision 0)" after the reference to WCAP-15918, Revision 2, in the current TS SR. The revised conditions related to the plant configuration with 42-percent SGTP may not remain bounded by the range of parameters specified in WCAP-15918, Revision 2, so the TS SR is being revised to allow for potential changes based on WCAP-16489-NP, Revision 0, which is the basis for the current proposed amendment. The NRC staff concludes that this is acceptable.

6.0 STATE CONSULTATION

Based upon a letter dated May 2, 2003, from Michael N. Stephens of the Florida Department of Health, Bureau of Radiation Control, to Brenda L. Mozafari, Senior Project Manager, U.S. Nuclear Regulatory Commission, the State of Florida does not desire notification of issuance of license amendments.

7.0 ENVIRONMENTAL CONSIDERATION

This amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (70 FR 75492, dated December 20, 2005). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

8.0 CONCLUSION

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

9.0 REFERENCES

1. Letter from W. Jefferson, Jr. (FPL) to NRC, “St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment Reduce Reactor Coolant System Flow With a Reduction in Reactor Operating Power,” dated October 21, 2005.

2. Letter from G. Johnston (FPL) to NRC, “St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment Reduce Reactor Coolant System Flow With a Reduction in Reactor Operating Power,” dated February 28, 2006.

3. Letter from G. Johnston (FPL) to NRC, “St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment Reduce Reactor Coolant System Flow With a Reduction in Reactor Operating Power,” dated March 28, 2006.

4. Attachment 8 to Reference 1, “WCAP-16489-NP, St. Lucie Unit 2 42-Percent Steam Generator Tube Plugging Licensing Report,” dated October 2005.

5. WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology,” dated July 1985.

6. Letter from B. Moroney (NRC) to J. A. Stall (FPL), "St Lucie Plant, Unit No. 2 - Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566)," dated January 31, 2005.

7. Letter from B. Moroney (NRC) to J. A. Stall (FPL), "St Lucie Plant, Unit No. 2 - Issuance of Amendment Regarding use of Westinghouse Alloy 800 Sleeves in Steam Generators (TAC No. MC5633)," dated April 18, 2006.

8. CENPD-139-P-A, "Fuel Evaluation Model," dated July 1974.

9. CEN-161(B)-P-A, "Improvements to Fuel Evaluation Model," dated August 1989.

10. CEN-161(B)-P, Supplement 1-P-A, "Improvements to Fuel Evaluation Model," dated January 1992.

11. CEN-372-P-A, "Fuel Rod Maximum Allowable Gas Pressure," dated May 1990.

12. CENPD-382-P-A, "Methodology for Core Designs Containing Erbium Burnable Absorbers," dated August 1993.

13. CENPD-275-P, Revision 1-P-A, "C-E Methodology for Core Designs Containing Gadolinia-Urania Burnable Absorbers," dated May 1988.

14. CENPD-275-P, Revision 1-P, Supplement 1-P-A, "C-E Methodology for PWR Core Designs Containing Gadolinia-Urania Burnable Absorbers," dated April 1999.

15. CENPD-404-P-A, Revision 0, "Implementation of ZIRLO™ Cladding Material in CE Nuclear Power Fuel Assembly Designs," dated November 2001.

16. WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," dated June 1988.

17. WCAP-10965-P-A, "ANC: A Westinghouse Advanced Nodal Computer Code," dated September 1986.

18. WCAP-10216-P-A, Rev. 1A, "Relaxation of Constant Axial Offset Control; F_Q Surveillance Technical Specification," dated February 1994.

19. WCAP-11397-P-A, "Revised Thermal Design Procedure," dated April 1987.

20. WCAP-7588, Rev. 1-A, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetic Methods," dated January 1975.

21. Letter from W. Jefferson, Jr. (FPL) to NRC, "St. Lucie Unit 2 Docket No. 50-389 Updated Final Safety Analysis Report Amendment No. 16," dated August 11, 2005.

22. CENPD-254-P-A, "Post-LOCA Long Term Cooling Evaluation Model," dated June 1980.

23. Letter from R. Gramm (NRC) to J. A. Gresham (Westinghouse), “Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-P, ‘Post-LOCA Long-Term Cooling Model,’ Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit,” ADAMS Accession No. ML0519200310, dated August 1, 2005.

24. CENPD-137 Supplement-P, “Small Break Model, Calculative Methods for the C-E Small Break LOCA Evaluation Model,” dated January 1977.

25. Letter from S. A. Richards (NRC) to P. W. Richardson (Westinghouse), “Safety Evaluation of Topical Report CENPD-404-P, Revision 0, ‘Implementation of ZIRLO Material Cladding in CE Nuclear Power Fuel Assembly Design’ (TAC No. MB1035),” dated September 12, 2001.

26. WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” dated April 1999.

27. WCAP-7979-P-A, “TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code,” dated January 1975.

28. WCAP-7908A, “FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO2 Fuel Rod,” dated December 1989.

29. WCAP-15918-P, Rev. 2, “Steam Generator Tube Repair for Combustion Engineering and Westinghouse Designed Plants with 3/4-inch Inconel 600 Tubes Using Leak Limiting Alloy 800 Sleeves,” dated July 2004.

30. Letter from G. Johnston (FPL) to NRC, “St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment Reduce Reactor Coolant System Flow With a Reduction in Reactor Operating Power,” dated April 24, 2006.

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Date: May 16, 2006

Attachment: Table 1

Table 1

Licensee Calculated Dose for Steam Generator Tube Rupture with LOOP 42-percent Steam Generator Tube Plugging and 89-percent Core Power

Case	**Worst 2-hour EAB TEDE (rem)**	**30-day LPZ TEDE (rem)**	**30-day Control Room TEDE (rem)**
SGTR preaccident iodine spike	0.30	0.29	3.81
Acceptance criterion	*25*	*25*	*5*
SGTR concurrent iodine spike	0.08	0.07	0.94
Acceptance criterion	*2.5*	*2.5*	*5*

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